COMMITTEE WORKSHOP

BEFORE THE

CALIFORNIA ENERGY RESOURCES CONSERVATION

AND DEVELOPMENT COMMISSION

In the Matter of:	)
	) Docket No.
Preparation of the 2007 Integrated	) 06-IEP-1E
Energy Policy Report	)
	)
Demand Response and Energy Commission	)
Load Management Authority	)
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CALIFORNIA ENERGY COMMISSION

HEARING ROOM A

1516 NINTH STREET

SACRAMENTO, CALIFORNIA

TUESDAY, JUNE 5, 2007

10:08 A.M.

Reported by:
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Contract No. 150-04-002

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Kinder Morgan

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ICE Energy

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P R O C E E D I N G S

10:08 a.m.

PRESIDING MEMBER PFANNENSTIEL: This is an Energy Commission workshop on demand response in the context of the Integrated Energy Policy Report. We are delighted to have not only the IEPR Committee here, but our colleague, Commissioner Rosenfeld, who has been pursuing this since he has been on the Commission.

And we're joined with representatives from the PUC, also our colleagues in this endeavor. To my right is Commissioner Bohn from the PUC, who's been involved with us on the IEPR throughout and very active. Commissioner Chong is not able to be here, but to Commissioner Bohn's right is Andrew Campbell, who is Commissioner Chong's Advisor.

And then to Andrew's right is Gabe Taylor, who is Commissioner Byron's Advisor at the Commission. To my left is Commissioner John Geesman; to his left is his Advisor, Melissa Jones. And then, of course, Commissioner Rosenfeld.

With that, we have a full day's agenda so I will turn it to Dave Hungerford to begin.

MR. HUNGERFORD: Thank you very much. I'm David Hungerford; I'm the Demand Response Lead for the Energy Commission currently.

PRESIDING MEMBER PFANNENSTIEL: David, is your mike on? You may be need to speak closer to it.

MR. HUNGERFORD: It should be; I just need to get closer. I always have that problem.

I'm David Hungerford; I'm the Demand Response Lead for the California Energy Commission.

COMMISSIONER ROSENFELD: David, you've got to get closer again.

MS. SPEAKER: Actually, David, you need to speak up.

MR. HUNGERFORD: I need to speak up?

MS. SPEAKER: You need to speak up.

MR. HUNGERFORD: Okay. Hi. There we go.

(Laughter.)

COMMISSIONER ROSENFELD: That's better.

MR. HUNGERFORD: I'm David Hungerford; I'm the Demand Response Lead for the California Energy Commission; and thank you all for coming.

To the folks on the telephone, the

presentations that we're going to go through this morning are available on the Energy Commission's website under the IEPR, on the IEPR page. If you go to the IEPR link on the main page for energy.ca.gov you'll see an IEPR icon. Click on that. And in the left-hand column you'll see programs, or rather an icon for documents. And you can click on that and get to this date; and click on that and you'll find the presentations for today's workshop and the agenda.

A couple of housekeeping issues. We ask that no food or drink beyond water be brought into this hearing room. We also, just outside this room, just beyond the glass walls are the restrooms. And in case of an emergency where we have a fire drill or some other kind of emergency, we should go out the two doors and out the emergency door just beyond those glass doors. And gather in the park across the street.

We also ask that everyone silence their cellphones. I'll do the same for myself.

And this workshop is going to be divided into two components, dividing the report that was available on the website last week. In the morning we're going to be talking about the load management authority the California Energy Commission has; and what possibly can be done with it.

And in the afternoon we're going to be talking about some specific applications of that authority.

We're going to begin now with Ahmad Faruqui, a contractor with the Energy Commission, who has written the whitepaper that most of you have read. And without anything else, Ahmad. Thanks very much.

DR. FARUQUI: Thank you very much, David. Good morning; it's a pleasure to be here. If you have had an opportunity to read the whitepaper you might find this discussion somewhat repetitive, for which I apologize in advance. If you haven't read it, congratulations, I'm going to summarize the main points for you and hopefully that will serve you in good stead.

The discussion this morning that I want to focus on is about the next generation of load management standards. That's the topic of today's workshop. And to provide some background and context for that discussion, I want to begin with a brief overview of the current deficit in the state's demand response policy.

To do that I'm going to recap some of the numbers that those of you who attended the workshop on April 19th might recall. Those numbers are shown in this table.

What this table shows is the impacts that are projected for the utilities' price-responsive programs for which a goal of 5 percent was established for the year 2007. In other words, for this year. And you see the numbers here; they are displayed in the various columns.

The first column is the expected peak demand for 2007. Now, some people have taken me aside and said 2007 is not over, the summer hasn't occurred yet, how do you know these numbers are true. And I don't. These are expectations. So the whole discussion, of course, is a planning discussion. We will know the true answer, if you will when the summer is over. But this is probably a fairly reasonable expectation.

The peak demand is projected for the three investor-owned utilities to come in at around 47,000 megawatts. The peak reduction from these price-responsive programs is expected to be about 1000 megawatts; 588 megawatts coming from

Pacific Gas and Electric Company; 373 coming from SCE; and 96 coming from San Diego Gas and Electric.

You can see that the percentage of peak represented by these impacts varies by utility. It's 3 percent for PG&E; 1.6 percent for SCE; and 2.2 percent for San Diego.

When you aggregate the results for all three utilities you get a number of 2.2 percent. So that's what I mean when I say that there is a deficit. I'm comparing the 2.2 percent to the goal of 5 percent. And that's the deficit that we are talking about.

Now, of course, I should add that about the goal focused on the impact of the price-responsive programs, everybody knows that there is a companion set of programs that are out there, the interruptible programs. And those programs, if they were to be counted, are expected to achieve an impact of 3.4 percent.

And some have argued that if add the two numbers, the 3.4 percent and the 2.2 percent, you meet the goal of 5 percent. Well, that's not quite the case. Because the goal of 5 percent was established specifically for the price-responsive program.

As far as I know there was no goal established for the sum total of those two kinds of programs. Maybe if such a goal had been established, we would have been able to add the two numbers and compare them to that other goal. I suspect that goal would probably not have been met, because the price-responsive programs are only meeting roughly 44 percent of their goal.

So that's the kind of deficit that we have currently being projected. And let me say a few more words about the deficit. Perhaps the best way to visualize the magnitude of the deficit is to say were the goals reasonable to begin with.

You know, some have argued that the goals may have been established too high. And the discussions with other states around the country I have been informed by many people that, oh, 5 percent is a very aggressive goal. Even 1 percent is not achievable. What are you talking about.

You know, I've had very friendly discussions with a number of people that I know well who can be very candid with me when it comes to telling me what they think of my opinions.

So, what we have had is a lot of

discussions. And so I thought, okay, let's step back in time a little bit here and just put the goals aside for a moment, if you will. Just, you know, a mental experiment. And take a look at what is the potential savings that's achievable.

There are three different concepts. And very very briefly at the last meeting I had provided some evidence on this. I want to expand on that a little bit, just to make people more comfortable with these numbers. They are not numbers that are pulled out of the ear. These are numbers that are based on good experimental data. They are based on programs that have been tried here in California or elsewhere. And those are the numbers we will be taking a look at momentarily.

But because there are three different concepts of potential, I'll take a minute here just to define the concepts, so we are all on the same page.

The first measure is called technical potential. It measures the outcome if all customers in the state were to use the best available demand response technology. Wave a magic wand, you know, sometimes it's been referred to -- I know ours here, I won't refer to here, Amory Lovins has a magic wand. If you wave the magic wand, you know, everything becomes super-efficient immediately.

Well, this is kind of that kind of experiment, except the difference is I'm focusing on technology that's available today. I'm not talking about lab technologies or concepts. I'm talking about technology that is commercially available today.

But the heroic assumption I'm making, and it is heroic, indeed, is that every customer now has the wand to be waved; they have that technology. How much of a demand response impact would that represent. That's the upper limit. And that's the technical potential.

Second one is an economic screen. It says we're going to only look at those options that are cost effective. And we will still assume that all customers have now been empowered, they have this new technology. So what is that impact and economic potential.

Obviously, there is a big issue, are you going to get that instantly, or are you going to phase it in. And that's where a lot of the debate occurs. That debate has occurred in the energy efficiency space for a long time. These are targets, and it's a question of timing, how you phase them in.

But I'm going to give you the steady state number if the economically available options were to be implemented today, how much would we save relative to peak demand. That's economic potential.

The third concept is market potential. And what that looks at is let's look again at the subset of cost effective technologies, but let's also recognize that not all customers are going to take them. So we will look at, you know, some realistic assumptions about what is a reasonable number of customers that are going to adopt the program. And if you bring that in, how much lower does the number become.

So, technical will be the highest number; followed by economic; followed by market. That's kind of what we expect intuitively, and that's also what we're going to see numerically, as seen here, in the next series of slides.

The first slide deals with technical potential. We have run the numbers; we have done the math; the spreadsheets are there. And I believe they will be made available to the various publics in due course of time when we publish the whitepaper, we can attach the spreadsheets as an addendum, or we can email them, you know. They are basically Excel files.

So what we have assumed here is there's full statewide deployment of AMI. Because one of the issues is that currently we don't have that; it'll take a few years; it's happening. So we are moving forward in time. We are assuming that's already occurred. Because otherwise you lose all of the residential and small CNI customers from your eligible population if AMI is not there. So we are assuming that's in place.

We are assuming 100 percent participation by all customers. This is not something that is just the focus of new construction. This is including every retrofit opportunity that is out there.

We have gotten the best data we could on how peak demand today is allocated by sector in California. And the estimates are shown here: 41 percent is residential; another 41 percent is commercial; 18 percent is industrial.

Now, you might disagree with some of these numbers. These are the best available numbers we could get. The final answer is not going to change a whole lot. But I just wanted to share with you what slices of the pie we are using here to come up with the total systemwide estimate.

We assume that all residential customers use the Gateway system. This was also called the ADRS technology. It's the whole-house technology. It connects multiple end users. In the experiment that was done as part of the statewide pricing pilot, there was an ADRS pilot that showed a drop of 43 percent in peak demand per customer. So that's the number we are using in this computation.

For all commercial and industrial customers we are using what is called automated DR, automated demand response. It's a piece of software that works with the energy management and control system that is installed in most large buildings.

You will see when we get into the first panel, the first two panels, there will be more discussion of the technology aspects.

We are assuming, based on the pilots that have been carried out thus far, that the ADRS technology can achieve an average reduction of 13 percent for a customer.

So, using the 43 percent number for residential, which account for 41 percent of the peak, and using a 13 percent number for the others, and doing a few other calculations, we arrive at an estimate of 25 percent reduction in peak demand. It's possible, under this scenario, that every customer is now equipped with these options.

Now, is 25 percent a large number or a small number. I guess we can discuss that later on. It is certainly a much larger number than the goal of 5 percent. So, just keep that in perspective.

The next calculation deals with the economic potential. It involves many more assumptions than I have time to go into, because now we are looking at a variety of technologies. Just to give you a flavor for that, within the residential, in potential calculation we assumed 100 percent of the customers were going with the Gateway system.

In the economic potential we have dropped that number down to just 10 percent. We are saying it's an expensive system and not every customer is going to go for it. Actually only one out of ten customers will go for it in the economic potential scenario we are looking at.

We are assuming 20 percent will go with the Smart thermostat, or perhaps the PCT. Again, you know, these are small percentages. Seventy percent we are assuming have no enabling technology.

And so with those estimates and using the numbers from the statewide pricing pilot, we arrive at a weighted average impact of 19 percent for the residential class. And then we get 7 percent for commercial through a similar series of calculations; 9 percent for industrial. We average them using the weights of the sectors, and we get a value of 12 percent.

So 12 percent obviously is half of the technical potential. What we're saying is that if we were to retrofit these options then the potential opportunity there is 12 percent. If we were to phase them in over a five- to eight-year period we would get 12 percent.

Now, this is incremental beyond where we are today. So this does not include the results already achieved today. The 2.2 percent number that is projected to be achieved this summer, these numbers are incremental and beyond that number.

Then we come to the market potential. And what we assume here is that customers use a cost-effective mix of enabling technologies, but only 40 percent of them participate in these pricing options, in these demand response options that are price responsive.

And what that does is it basically gives us a number of 5 percent. That's a 5 percent beyond the 2.2 percent that's currently being achieved. So if you were to add those two numbers, you could say that the market potential, including the 2.2 is around 7.2 percent.

PRESIDING MEMBER PFANNENSTIEL: Ahmad, I just want to make sure that these potentials that you're calculating, you're estimating, are they all price-responsive potential? They're not the other automatic control potential.

DR. FARUQUI: We are not including direct load control or interpretable rates in this. But what we are including are the enabling technologies that go with the price responsive --

PRESIDING MEMBER PFANNENSTIEL: Well, but the price-responsive --

DR. FARUQUI: Exactly, that's right. So these do not include those other programs.

PRESIDING MEMBER PFANNENSTIEL: But this is comparable to the 5 percent goal that we've set out?

DR. FARUQUI: That's correct. These are all within that sphere of, you know, different slices on the 5 percent goal.

Okay, so if we take a moment then to just focus on the 5 percent number, which, of course, is a fifth of the technical potential, and about 40 percent of the economic potential, that's what we are calling our market potential, what is the value of that 5 percent number.

Well, without even looking at environmental issues or job creation issues or other economic issues, and just focusing somewhat narrowly on generation capacity costs, generation energy costs, and transmission and distribution capacity costs, if we just focus on those numbers, the numbers that are typically considered in a cost/benefit analysis or demand side options, using the standard practice methodology kind of approach, what does that amount to.

Well, let's first look at avoided generation capacity costs. We're looking at 3000 megawatts of avoided peak demand. Or about 50 combustion turbines. If you use the cost of new capacity, a number that many people are using these days, $52 per kW-year now, that's by no means a hard and fast number. There are many other numbers around, but I would say that's like in the mainstream of numbers, $52. We get $200 million in avoided costs for a year.

Then we look at the electricity generation costs and we look at the energy consumption that goes down during the peak hours, the critical peak hours. We get another $20 million in avoided costs from the energy side. Both of those are generation numbers.

Then let's look at the transmission and distribution numbers. Those are obviously harder to estimate. They're very system-specific. There's the issue of coincidence between the system peak and the TND peak and all of those factors.

But using a rule of thumb, looking at studies around the country, 10 percent is actually, I would say, a conservative number for transmission and distribution costs; 10 percent of the others. So we get a 20 percent value from that.

We add those up and we get $240 million per year. So if you take the net present value over the next 20 years, we get a $3 billion net present value. And that's the benefit associated with a reduction in peak demand of 5 percent.

Now, the 5 percent, of course, that I'm talking about is coming from the price-responsive programs. If there was another 5 percent reduction from the other programs it would have similar benefits. But I'm not counting those. This is just staying focused on the price-responsive program.

And the bulk of the benefit in my computation is coming from generation capacity. That seems to be in the driver's seat as far as these benefits go.

We all agree generally that those are the magnitudes of benefits. The issue is what's keeping us from getting there. This is simply a slide I have pulled up from my previous presentation to you which enumerates 14 barriers to the achievement of this HDR potential.

And if you step back from this list and say, well, 14 is too many, you know, what are the main themes. Well, there was a lot of discussion that took place after the last workshop ended on how you consolidate these into a couple of major nuggets, if you will.

And so we have done that. We find that the barriers fall into two broad areas. First one is a need for dynamic pricing. The absence of dynamic pricing obviously, by definition, it tautological, is the main reason why we don't have a lot of impact in the price-responsiveness program, is because the pricing is not there.

So, a lot of the other barriers become subsets of the pricing issue. Like develop better and more innovative rate designs that customers can relate to, that customers find interesting, that customers can use to respond to.

Of course, there is he big wall out there with AB-1X written on it. We have to deal with that. We have to find a way to either change the wall or find a way around the wall, or perhaps jump over the wall. Whatever the issues are, it's certainly a huge barrier when it comes to residential and small CNI. It actually -- just residential, the rate issue just applies to residential.

The rest of the market, which is about 60 percent of the peak demand, is not affected by AB-1X. There's a lot of sentiment that if only AB-1X would go away we would be able to achieve these.

Well, for the other 60 percent AB-1X is not a barrier. And we still have that issue. So obviously it's one of those, you know, big bubbles where if you touch from one side it goes on the other side. If you touch from the other side, it bulges out of the other side. It is a complex, amoeba-like problem that we have.

A related issue is maybe the issue of what are realistic goals for demand response. I think we need more communication, more understanding that these goals are achievable; that there is a perception that they are somehow not achievable. I think there's more work needed to convince the various parties that these are within the realm of feasibility.

We may want to look at our cost/benefit methodologies and make modifications to accommodate the nuances of these new pricing programs, because they do involve loss of service. Something that's not easily quantified in the existing cost/benefit tests.

Ultimately there's a lot of opportunity to educate customers about the benefits of time varying and dynamic rates, and that remains a huge challenge. All of those are part of the cluster of issues that I'm calling dynamic pricing needs.

Then we come to the technology needs. Certainly AMI is a known technology; it's just a question of timing. I've listed it here because until that happens a lot of these benefits for about 60 percent of the market will remain elusive.

We also have to equip customers with the enabling technologies because the bigger impacts will not come unless we have automation.

And then ultimately we have to design rates with an understanding of the response that customers are able to provide. We have to provide them realistic estimates of benefits.

So, you know, it's an interaction

between prices and technology. People ask, well, is there anything about the prices that is not fully understood today. Is there some magical pricing design that's hidden. Do we have to go on a journey and find it, and only then will these benefits become apparent to us.

My personal answer is no. I think the designs are well known, well understood. They just have to be demonstrated. I think there is more homework needed to convince the various parties that these are achievable designs that will not hurt the customer. They will benefit a lot of the customers.

I think one of the graphs you might remember in the last presentation I showed on April 19th was that if you provide the appropriate design that 97 percent of the customers can benefit from these rates, that's the kind of area in which some more work and convincing, perhaps, is needed.

But they are within the realm of feasibility. The technologies I'm talking about, none of them need to be invented. They're already out there. It's just a question of economies of scale and commercialization.

And a lot of that won't happen until the price is changed to create that opportunity. It's like a "Catch 22". Without the price the technology will not penetrate the market; unless it penetrates the market, the economies of scale will not occur.

So we are caught in this conundrum, and we need like a Gordian Knot being cut kind of solution to move forward, perhaps.

Okay, so one way, maybe, to cut the Gordian Knot is to look at another way of doing business. And this other way requires us to go back in time. So, in the last several weeks a lot of what my colleagues and I and Dave Hungerford have done, is put on a historian's hat, I guess, and talk to people who were present when the first generation of load management standards were developed.

And we have talked to people who were there. We have talked to people who were not there, and some of them were in high school, they reminded us. I was in grad school. So we have had all kinds of competitions as to who was there in 1978.

Well, you know, apart from the personal

aspects of it, the reality is the Energy Commission did have an opportunity and fulfilled that opportunity in the late 1970s by pioneering the first generation of load management standards.

In one of the documents we came across a number which I thought was very interesting. Somebody actually made a projection with those particular standards. The impact that they were projecting was a 7 percent reduction in the state's peak demand.

And that was the goal that they established for themselves. As far as I can tell, no evaluations have survived the last 30 years; none that I have touched. They may have been done. So I don't know quite honestly whether the 7 percent goal was achieved or not achieved. But it certainly was put out there. It was, you know, a stretch goal.

As you will see in both the morning discussion and the afternoon discussion, the standards enjoyed a certain amount of success. They were not 100 percent successful, but they were not a failure, either. They made a major contribution; they pushed the industry forward. And that's, I think, you know, something that's very encouraging as we look back at them.

Now, switching gears, I think all of you are very familiar with the Energy Commission's Title 20 and 24 standards that focus on energy efficiency, the appliance efficiency standards and the building codes. Well known; admired throughout the nation. And so far imitated poorly, at best, by the other states.

Recently had an opportunity to discuss those standards in Florida with some of the people there. And, you know, everybody looks at California's graph, which we have reproduced in the previous report, where you see this line of per capita electricity consumption in California held to under 7000 kilowatt hours per capita over a very long period of time. And you see the national line rising and rising and rising. And between the two of them, the gulf widens.

So, the people in Florida, you know, facing rapid load growth, they're very concerned about how is California being able to achieve this, and they haven't. And there has been some concern.

And so one theory that was put forward was, oh, maybe California's had a lot of illegal immigrants who are low income, and who cannot afford the appliances, et cetera, so that's why the numbers are flat. Of course, that's neither here nor there.

I mean these are a very real tribute to the standards and the programs that the utilities and the State of California have achieved. And people are, you know, reluctantly and grudgingly accepting that.

And what's interesting is that in the case of California, the standards, these two account for half of the efficiency gain that has been achieved.

So, if you look at these two facts, the load management standards have a good history; maybe not a perfect history, but certainly a good history. And you look at the Energy Commission's building and appliance efficiency standards, which have an outstanding history.

So that says, well, maybe it's time to look at another way of achieving the demand response goals. And so let me give you in the rest of this presentation, a brief, historical update of load management standards.

Just out of curiosity I'd like to know

how many people in the room were around in 1978 as professionals in the energy business. Okay. Well, it's important to keep that mind as you look at these. And some of you might even remember these standards.

So, just a quick recap of history here. This should have been done as a video, but I guess we're staying with the low-tech. The early 1970s people were building new appliance, there were cost overruns, there were delays and then there was the big oil crisis.

1974 the Warren Alquist Act created the Energy Commission. It starts doing business at 1111 Howe Avenue. I was there as a grad student; I think several of you were there in various capacities.

So, 1976 the Energy Commission is ordered to develop load management standards. 1978 the Energy Commission proposes load management standards. There was a lot of work that was done, a lot of pilots. And the next panel that's going to come up actually will provide you with a lot richer historical perspective, I think full of nuances that I cannot talk to you, because back in those days I was doing forecasting. There were other people doing load management. And I didn't even know what the term meant. So we will have some of those people, we are lucky to have them here, talk about what it was all about.

Okay. The Public Resources Code of California, take a minute to look at that. It says that by July 1, 1978, the Energy Commission shall adopt standards by regulation for a program of electrical load management for each utility service area.

There were specific suggestions that were listed. Adjustments to the rate structure. Development of end-use storage systems. And mechanical automatic devices for controlling peak. This was the infancy of load management, so some of these terms look very dated now, very archaic. But that's how it was.

There were requirements of the standards. Load reduction, which meant changing the shape of the load duration curve. They had to be cost effective. And the technology had to be feasible.

So a lot of the pilots that were done actually looked at the feasibility of the technologies, and looked at the cost effectiveness. Because all of those were new frontier topics. Direct load control was not an established technology back then. Something called timers were a novelty. This is 30 years ago, so, you know, you would expect those things to have always been around, but they've not always been around.

What was interesting was the standards covered all the utilities in California, including the investor-owned and the publicly owned organizations.

So, after a lot of soul searching, a lot of review, critique, workshops, panel discussions in 1978 four specific standards survived the scrutiny. The first one was load control. The second one was swimming pool filter pumps. The third one was nonresidential, it was for commercial; it wasn't really load management as you will see in a moment, but the idea was to look at the commercial buildings, see what opportunities are out there. And then there was a standard for establishing a tariff for achieving load management.

The load management standard involved

putting switches so that would allow various appliances to be cycled. Included, interestingly, space heaters, certainly new to me. There's not much electric space heating in California. Water heating. Again, not much electric there, either. And air conditioning.

But it was all inclusive. It included those three. And ultimately, I believe, and we will hear more about this in the panel, the centerpiece and the one that survived the decades, was the air conditioning control standard.

A customer would get a rebate or an incentive in return for the loss of service that they would experience when their appliance of interest was being cycled.

The standards involved a three-phase evolution. The first one was a development phase, concept development, proof of concept, if you will. Then there was some testing and evaluation. All carried out by the utilities. And systemwide implementation followed, or was supposed to follow, and did in some cases and did not in other cases.

Swimming pools, while the idea was simply to make sure that the pumps didn't run during the peak hours. And so there was a lot of education for customers, to tell them why it would be beneficial to society, as a whole, if their pumps didn't run during the peak hours. And they would really experience no loss of service. It was almost like a win/win kind of an opportunity.

It still remains, I think, a target of opportunity that hasn't quite been achieved around the country. People talk a lot about it, but it seems to always falter and not quite happen. I'll not get into the reasons for that.

The gist of it is the pilot program was designed to demonstrate the success of such a technology; and the goal was to contact all eligible customers within one year of the program's approval. And that was certainly an audacious goal, because a lot of people with swimming pool pumps.

But, you know, that was sort of what you come across in the documents as you read the -- some of the documents took forever to find, by the way. Some didn't seem to exist. Some were tracked down. The archiving quality was put to the test. And when we did find them we sneezed a lot because they were just laden with mites.

Nonresidential load management standard. This applies to the commercial buildings. Focused mostly on doing audits of these buildings. And the audits actually included energy conservation, not just load management.

So this was when energy efficiency and load management were used synonymously. And, you know, perhaps in the future we might again like to have such a situation. There was no bifurcation that was apparent as we looked at this particular standard.

The cost of audit was included as a fixed charge in the monthly bill. At the time that this was happening the pilots in California suggested that the audits, by themselves, would achieve a less than 2 percent reduction in consumption. Just the audits, by themselves.

But the suggestions from the audits, were they to be implemented, could achieve a 20 percent reduction. And so that establishes a goal for 1985.

There was a standard for tariffs. And what this involved was a lot of discussion and debate about marginal cost pricing. And this is a time when I know where Jackie and I were, and I know some of you were into the (inaudible) of the electric utility rate design study that EPRI, at the behest of NARUK (phonetic) was doing. And produced a 100 reports, several of which focused on how to do marginal cost pricing.

The Energy Commission was very active in that, as were the California utilities. And there was a lot of discussion and debate and some resolution. The utilities were required to file the proposed rates with the PUC because ultimately the PUC was going to be still the tariff-setting body.

There was a pilot a PG&E that reported a reduction of 35 megawatts from nonmarginal cost based TOU rates. There was some controversy whether you had to do marginal cost. There were many people who argued you didn't need to, you'd also do accounting costs.

And one of the big conclusions of the rate design study was let's not get into that debate. Do it however you want to, but do time-of-use. Whether you take the accounting road or the marginal costing road is a secondary issue.

And so this demonstration showed that you could actually do nonmarginal cost based TOU rates; get a 35 megawatt reduction. And so if you were to do marginal cost based rates, you would probably get an even bigger reduction.

But at some point this whole discussion solidified into a recommendation that was implemented by the PUC that all load above 500 kW in the State of California would be placed on time-of-use rates.

California, I believe, was one of the first states to go through with mandatory time-of-use rates for these large customers. There was no opt-out/opt-in discussion. These were mandatory and they went in. And they have achieved tremendous reduction in the load shape.

That actually creates a challenge because if the load shape's already modified, then obviously it's a bit more difficult to modify them further. And that continues to be a topic of discussion.

The reality is customers do respond to rates. And much before the pricing experiments were carried out, this actual implementation showed that results could be expected through these kinds of tariff ideas.

So those were the four standards. What

did they achieve collectively. There was a slow initial response with the standards. Some people didn't know what the standards were; some people still wanted to know how load management was spelled. There was a lot of debate and discussion.

At some point it solidified; workshops were held in 1979 to show that the technology was feasible and that customers could participate, but more needed to be done to get customers involved.

There's a report from the Governor's energy conservation task force in January of 1980 that reinforced the need for immediate response. That came from the side, if you will.

Utilities responded to these load management standards. They also did other things on the energy efficiency front. The State of California survived the load capacity margins of the early 1980s. And then at some point there was actually a surplus, in the mid to late '80s.

And that surplus, some people that we've talked to, it's not clear to us what happened then. There is no further history. It's sort of like you have the firs chapter and then there are no other chapters in the book. It's sort of like the river disappeared into the desert and there is nothing more written.

Well, some people say that happened because there was a capacity surplus. It drove away the need to manage the load shape. Others say, well, people moved around and the initial movers and shakers were at different jobs. Other people say, well, energy efficiency became the more exciting thing to do. I honestly don't know what happened. I'd welcome, when we have the open discussions, some commentary on that.

But what is interesting is, in spite of that fact that the river disappeared in the desert, two programs survived and they produced lasting impacts.

The first one, you all know, is the time-of-use rate program for the large customers which was above 500 kW; but that ceiling came down, and now it's at 200 kW as a result of the western energy crisis.

The residential load control programs at some utilities clearly are a continuation of the early load management standards, even though there's a dotted line somewhere along the way.

So those have survived and that shows a

little historical overview, if you will, shows that they were interesting; they produced results; and they're probably worth revisiting.

But let's probe a little bit. What can we learn from that experience before we get into the next generation discussion in the afternoon.

And these are reasons that I have, along with Ron and David, distilled from interviews. They're not written up; there is no evaluation, as I said, that I could put my hands on that was either a process evaluation or an impact evaluation of the early standards. You know, that might be something worth doing, you know, in a formal sense at some point if the Commission decided to go further.

These are very impressionistic lessons that I have distilled together for you here this morning. The standards seem to be colored by an advisory nature. The statement is mine, and some of you can argue with it, but I heard this so many times that I have decided to make that the first bullet here.

The Energy Commission does not have independent authority to enforce the standards, by which I mean the load management standards, as it does with the appliance and building standards, Title 20 and 24.

Now, take this not as a statement of fact, but as a statement I heard and I'm just relating to you. Four out of six people that we spoke with told us that. Now some of them were actually involved in the early standards; some were not. But it's interesting that, you know, four out of six people say that. And there's certainly some confusion on that issue and certainly something that needs to be addressed.

There was the issue of administrative constraints. And by that what I mean is who will implement the programs. Will the Commission implement it? Will the utilities implement it? Would the PUC implement it? And now, with the emergence of the Cal-ISO, will the ISO implement it.

So there's certainly an issue of even if there's agreement on intent and motivation, there's the issue of mechanics and tactics. And the appropriate capability to implement them, just reading between the lines, I was told early on that there was confusion back then, as well. At some point it frittered away, and needs to be reconstructed and reconsidered if the standards are going to be revisited.

It's not something that you can put your car on cruise control and go 75 miles per hour on highway 80. It takes a lot of active management.

Technological issues. There were, I'm told, some technical issues with the pool pump timers. And there was some confusion about the technology. Apparently significant manual efforts were required by the users. Now maybe in the years that have come and gone, the problem has been overcome. But there was at least in one instance a technology problem that stymied progress.

There was, of course, the issue of the voluntary participation. With the exception of the mandatory time-of-use rates, the standards did not require or impose customer participation. And so the issue of customer education, customer recruitment, customer satisfaction, those issues remain very large issues.

Unless the standards are reconsidered and defined differently so that they are of a different character, in other words, either a mandate or a default configuration, we will still have this issue.

A comment was made that the standards ultimately relied on the utilities as being the enabling arm of the standards. And that a private market for demand response did not come into being. I think this comment is particularly timely, because now we have a lot of these third-party aggregators. We have a lot of these companies, I understand, and all kinds of IPOs are happening. A lot of excitement on Wall Street with the opportunity.

I think a lot of those parties would like to play a role in being the enabling arm of any standards that are reconsidered. And so that's something worth thinking about.

And then, of course, we have the cyclical nature of capacity shortages. We have this boom/bust cycle in our industry. And I see no easy way around it. Interest wanes and then spikes. We have blackouts. If you have problems everybody's focused on it. If you don't have problems people say, well, you know, this is a free market, people can do whatever they want; they can use as much power as they want. Aha, but at what price.

Well, they don't want to change the price. The price should be whatever it's historically been. But somebody has to wrestle with that issue. I came across this line from John Dingle, reading Time Magazine yesterday; it had a profile on this granddaddy in Congress. And the line simply was "The easiest policy is no change." Anytime you want to change a policy you become unpopular. And that's why a lot of people don't want to change.

But the status quo is suddenly endowed with the best characteristics, even though it has subsidies, as we talked about in the last discussion; it has inefficiencies, as I've shown, $3 billion of money being left on the table by not doing the market potential of DR. Those are the issues that I think are worth thinking about as we revisit the next generation of load management standards.

I'll turn it back to David. Thank you.

MR. HUNGERFORD: Thank you, Ahmad. An excellent summary of the paper. And for those of you who haven't had an opportunity to read the paper, there's a lot of nuance and details in the paper that was not included in this discussion.

We're going to open up for the next panel discussion. The participants in that discussion are Roger Levy of Levy Associates, who was here during the load management standards time, although he looks a great deal younger than that. And then apparently worked also with PG&E on the implementation of their load management standards. And he has put together a presentation for us.

And following Roger's presentation there will be a discussion where one of the Energy Commission legal staff, Jonathan Blees, will join us for discussion on the details of the -- the specific details of the load management authority as it is written into the Public Resources Code.

So, thank you, Roger, for joining us.

PRESIDING MEMBER PFANNENSTIEL: David.

MR. HUNGERFORD: Yes.

PRESIDING MEMBER PFANNENSTIEL: After Roger and Jonathan, will Ahmad, Roger and Jonathan all sit as a panel in case there are questions of all of them?

MR. HUNGERFORD: We can certainly do that. And if you notice from the agenda, one of the slight agenda changes is that we're also going to have an update on the current state of enabling technology for demand response from Ron Hofmann and Mary Ann Piette of the Demand Response Research Center at Lawrence Berkeley National Labs.

And so if we drag on into lunch a little bit, that's fine. We can shift our lunchtime. There's a little bit of extra time built in there for this discussion.

So, yes, we can have that discussion after the panel. So, Roger.

MR. LEVY: Good morning, Commissioners; good morning, Staff. A brief history. I feel like a dinosaur here this morning. I started at the Energy Commission in 1976 and was actually brought in to facilitate and work on the load management standards. I was part of a larger group then, about eight people eventually; of which at least one other one is still sitting in this audience today, which is encouraging. We're not at that point in our lives yet.

What I'm going to do is go through briefly some issues that David asked me to address on the standards, give you a brief background.

First, the environment in 1976.

Understand that PURPA had not yet been implemented or adopted. It was not adopted until 1978. The utility situation, from an industry perspective, is that they had been going through about 25 years worth of load building. This was the area of Ready Kilowatt, of the all-energy home, great successful programs.

Also, because of declining costs, declining block rates, relatively unsophisticated load forecasting methods, I can't tell you how many times I sat down with utility representatives back in the mid '70s, and forecasting consisted of putting a straight-edge ruler on a couple of dots from where peak demand was, and drawing a line out into the future.

And very little customer information. Because at that point customers were always getting lower rates, getting more for less. There was less focus on customers.

The CEC situation was it was a brand new agency; it had been established in 1974. There were no appliance standards yet; there were no building standards; and there were no efficiency or demand response programs of any kind.

Now, the key utilities that were targets or participants in the activities that embraced the load management standards at the Energy Commission were the three investor-owned utilities, PG&E, Southern Cal Edison and San Diego Gas and Electric. As well as the two largest municipal utilities, SMUD and LADWP.

David asked me to go over the process with you. The process was sort of evolutionary because there were no ground rules here. Not only was there no building standards or energy efficiency standards, at the Energy Commission in 1976 there were no rules of any kind, no bureaucracy, so everybody was figuring things out as we went.

But there were really four steps in this process. One was a series of pilot projects, which I'll describe in a minute. They were very much collaborative projects. The relationships with the utilities at that time was exceptionally strong and good. There were no problems getting data, getting cooperation.

There were internal studies done by the Energy Commission Staff where staff actually went out and did energy audits. They actually did field research work, did technical papers. And there were consultant studies. Few of those because at that point there really weren't a lot of consultants specializing in the energy area.

The recommendations from all those fact finding or studies was brought to a Committee of the Commissioners. The results were reviewed and what was recommended out of those committees was essentially the four load management standards that Ahmad produced for you this morning.

We held public hearings statewide. The Energy Commission Staff actually traveled, not the Commissioners, up and down the state holding public hearings. And finally, the results of those public hearings was brought together in a staff report which was recommendations to the full Commission for the adoption of the standards, the four standards which Ahmad showed you earlier this morning.

So, Ahmad represented a series of pilots. In fact, there were 24 pilot projects that were conducted that began in 1976. This is actually -- all these pilots were components of one of DOE's very first energy pilots. And California had the biggest share of those in the nation. I was the Project Manager and the facilitator on all those projects.

We worked with all three of the utilities, the investor-owned, and both the municipals. All combinations of these pilots, as you can see. There were a lot of time-of-use tariff pilots. There were quite a few load control pilots for space heating, water heating and air conditioning.

There was one very innovative time-of-use pilot at San Diego Gas and Electric; that's the second bullet item. It was actually a dispatchable time-of-use rate that today would be classified as almost critical peak pricing.

All these pilots had experimental designs; they had very innovative marketing plans; and research agendas that were, in fact, very comparable on the scale to the statewide pricing pilot, which the Energy Commission and the three investor-owned utilities pursued about two years ago.

The studies that were also done in conjunction with load management standard basically covered the range of opportunity in the entire marketplace. And understand that, as Ahmad mentioned, there was very little activity going on in load management in this country. Load management, in fact there was a reference, I think, in his report to 3500 utilities that had some form of load management.

Most of that was actually water heater load control, but not for the purpose of peak load management. It was for the purpose of load building for controlling, moving, getting larger water heaters for building offpeak load, and then putting timers on them to keep them off during the peak, to really build load for utilities as they were growing their load in the '50s, '60s and early '70s.

But as you can see from this list, we covered the entire range of activity in the industry, agricultural, industrial. There were technology studies, customer acceptance studies. There were workshops being held and quite a lot of activity in the rate design.

And the last item on the list is the cost effectiveness analysis. That was a necessity mandated by the standards. This actually was the child that turned into the standard practice methodology.

So when the Energy Commission finished

with it, which was a very crude start, it was assumed by the Public Utilities Commission several years later; and has since evolved into the standard practice methodology, which is today being reviewed in an OIR of its own by the PUC.

So, to repeat one of the items that Ahmad had mentioned is that the Commission and the staff were charged with, at the very least, considering load management standards that involved rate structure adjustments, devices for control of daily and seasons peaks, and end use storage systems.

He also mentioned that storage was not addressed; and the reason for this is the quote at the bottom of this page, which said the staff didn't address it because at that point in time the technology for storage either wasn't adequately developed or wasn't deemed to be cost effective, given the rate structures of the cost in California.

Finally, we come to the four standards that were developed. And what I was asked to do was provide you with a little insight on each of these standards.

I'll start with the residential

appliance control standard. This is basically what has today remains as air conditioner load control. All of the utilities were mandated, through the standard and through the authority of the standard, to implement some form of air conditioner load control.

In the standard there was actually a goal of achieving 25 percent saturation of control switches over a certain period of years. There were differences back then between the utilities and the Commission Staff. One of them was whether this goal was achievable or not. Twenty-five percent they thought was too high based on some of the pilot work; they thought that the most that could be achieved was 23 percent.

However, actual implementation varied and showed that, in fact, market planning and innovative marketing techniques could achieve a lot more than that.

PG&E, in their implementation of the standards, actually achieved in one segment, one part of their pilot, an 80 percent saturation rate; that's 80 percent of the customers in the targeted geographical area that had air conditioners and that were potentially capable of signing up for the voluntary program, actually signed up and participated.

Edison actually took it one step further. they had a target community where they achieved 99 percent saturation.

What I can tell you is that nationwide air conditioner load control and water heater load control are still the largest demand response programs in North America. That the cooperative utilities, the small rural utilities, tend to have anywhere from mid 20s to low 40 percent saturation rates of load control for both water heaters -- or, for water heaters, space heaters and air conditioners. Investor-owneds tend to have a lot lower percentage saturation.

The second standard was actually labeled commercial energy conservation surveys. And, in fact, this was possibly by accident or possibly by design. But energy efficiency, conservation and demand response were essentially all integrated into one. They were not separated out as Ahmad had indicated. They were considered to be a singular, nonseparable goal for buildings.

And the goal of the standard was a 5 percent reduction in peak reduction, coincident peak reduction, and a 10 percent reduction in overall energy use. So it had both efficiency and demand response goals.

As Ahmad indicated, the utility surveys, the audit surveys the utilities had been conducting had a history of achieving less than 2 percent reduction in energy use.

However, there were isolated incidents, and then some not so isolated incidents. What I've listed here are a couple of examples. PG&E headquarters actually did an energy conservation survey in accordance with the standards, and achieved a 30 percent reduction in energy use.

Lawrence Berkeley Labs ran DOE studies; consistently identified potential for 10 to 40 percent reductions. And the Demand Response Research Center most recently with its audit DR program, shows potential for 10 to 30 percent reductions in peak demand. That program does not address energy efficiency.

The load management tariffs was more of an advisory type of standard. And the purpose, again, was to propose and look at marginal cost rates. And very simply the reason was because at the time average costs underestimated substantially what the incremental cost of new additions to plant and transmission distribution were reporting.

And the problem then and the problem that continues today is there are uncertain definitions in methodologies for determining marginal cost. It has been a 30-year argument that continues to roll into the future. And I'm not sure where it will end.

The last one, the swimming pool pump standard. There was very little resistance to this. All the utilities were very, I wouldn't say eager, but very cooperative in pursuing this standard. And the problem that existed with this is a technology problem that actually continues to this day.

And the technology problem was actually rather simple. Is that, I believe, for the most part, swimming pool pump clocks are all still electromechanical. Anytime there's any kind of outage or anytime a service technician comes to service the pool they turn the clock off, and the minute that happens the timer goes out of whack. And consequently the little timer clips that you put on to keep your pool offpeak no longer do that.

So I don't know whether a load management standard can address that problem. But there are probably some technology standards that might address it rather easily. And the Commission is probably in a position to look at that.

That actually concludes the history of load management standards. Any questions?

PRESIDING MEMBER PFANNENSTIEL: Thanks, Roger. I think that we may do some questions of the whole panel. David.

MR. HUNGERFORD: All right, I was prepping my witness. Okay, we're going to ask Jonathan Blees, legal counsel for the Energy Commission, and Roger and Ahmad to please go to the table and form an actual physical panel.

And I have a few questions for Jonathan and then we'll open the discussion for the Commissioners to ask questions and to satisfy their curiosity.

Just take a seat at the table where there are microphones.

All right, Jonathan, there are a couple questions about the specifics of the standards that I've received from people since the whitepaper was published.

The first of them is does the phrase "by July 1, 1978" mean that the opportunity for adopting new standards is now lost to the Energy Commission?

MR. BLEES: No, it does not mean that; it simply means that the Legislature wanted the Commission to adopt the first set of standards by that date.

But even had the Commission failed to do that, it would not have affected its authority. And certainly the Commission's authority to revise the existing standards or to adopt new standards is not affected by that language.

MR. HUNGERFORD: All right, thank you. The second question is, Roger went through a slide on the process as it was invented back in 1978. Given the intervening years, the increase in requirements for public participation and regulatory processes and that sort of thing, what would you imagine the process would be for adopting a standard and where are the uncertainties, as far as you are concerned, that would need to be worked out within the Energy

Commission? For us to go through our process.

MR. BLEES: For the Energy Commission to adopt any load management standard it would have to follow the standard rulemaking process that's established in the state's Administrative Procedure Act.

In a nutshell that requires publication of a draft proposal and supporting information; a public comment period of at least 45 days; an additional public comment period of at least 15 days if any revisions are made to the original proposal. And then, of course, for the Commission a final public adoption hearing.

The statute, which I assume you've been over, does require the Public Utilities Commission to approve any changes in a load management standard that concern tariffs or rates. And so the CPUC would have to follow its own regulations and statutory requirements applicable to it in approving any such tariff or rate changes.

The load management statute also implies that the boards of publicly owned utilities also have to approve any changes in rates or tariffs in whatever statutory or regulatory requirements are applicable to them, you know, such as the Brown

Act, which requires local governments to act in public when they are making decisions, would be applicable to them.

Does that answer --

MR. HUNGERFORD: Yes, it does. Yes, it does. And I'd like to follow up a little bit and ask more the nuance of what obligation is the CPUC and are the muni boards under to adopt these standards that the Energy Commission has set up, without adjustment or with adjustment, with changes?

MR. BLEES: Well, approval by the CPUC and by publicly owned utility boards, if any approval is required at all by the latter, those are only applicable to Energy Commission load management standards involving rates or tariffs.

The other types of potential standards called out in the Warren Alquist Act, that is end use storage systems or any mechanical or automatic device or system, any load management standard that the Energy Commission adopts in those areas, or anything else outside of the rate and tariff area, go into effect without any further approval by the CPUC or the local muni boards.

The statute also says that with regard

to any expenses or capital investments, that the rate-setting authorities must allow those matters to be expensed, or the capital investment to be rate-based.

MR. HUNGERFORD: All right, thank you, Jonathan.

I'd like to open it up to the Commissioners and Advisors for questions. Thank you.

PRESIDING MEMBER PFANNENSTIEL: Thank you, David.

Let me start. In Ahmad's presentation he talked about some various issues that he had heard raised by others.

One was that many people felt that the Energy Commission, and I'm going to quote from his presentation, "the Energy Commission does not have independent authority to enforce the standards as it does with the appliance and building standards."

Is there anything, Jonathan, in the legislation that would distinguish our authority in the load management standards, our authority in appliance and building standards?

MR. BLEES: I do not read the statute

the same way that my former colleague does. Again, the PUC, probably local muni boards, must approve rate and tariff changes. But the other load management standards are binding on the utilities. And the Energy Commission certainly has the authority to carry them out.

The standards that Roger was describing a few minutes ago, the pool pump standard, the cycling programs and so on, were not, you know, purely voluntary. Those are programs that the utilities had to carry out.

DR. FARUQUI: I think that's why we have clarification because Jonathan was not here when I had that bullet up on the slides.

That was not my personal interpretation. It was just a statement I was attributing to the various people we had spoken with. And four of six people we talked to seemed to mention that as a concern.

So I was just saying that there is a perception out there. And I was just reporting --

PRESIDING MEMBER PFANNENSTIEL: Even more importantly, Ahmad, that was not your legal opinion --

DR. FARUQUI: That's right. I mean, not

being an attorney I cannot obviously provide such an opinion. But just by way of an anecdote, it seemed to come up more often than I had expected it would come up, including from some people who were involved in the early, you know, the load management era, if you will.

PRESIDING MEMBER PFANNENSTIEL: One other --

MR. BLEES: Well, then I disagree with the people who misinformed my former colleague --

(Laughter.)

DR. FARUQUI: Thank you.

PRESIDING MEMBER PFANNENSTIEL: There's a lot of that. On the question of our ability to adopt a standard for appliances and building standards, they must be cost effective and they must be technologically feasible.

Are those the same two criteria that we would have to meet for these?

MR. BLEES: Essentially, yes. The cost effectiveness criteria applicable to the appliance standards, as expressed in terms of cost effectiveness to the consumer, as I recall, the building standards just say cost effective.

The criterion in the load management

provision is that the standards shall be cost effective when compared wit the costs for new electrical capacity.

As you said, there is also a technologically feasible criterion for the load management standards.

PRESIDING MEMBER PFANNENSTIEL: Questions?

ASSOCIATE MEMBER GEESMAN: Ahmad, if I focus on your presentation or your report, you quantified the market potential at $240 million of benefit per year. But if this is being teed up for a regulatory approach, wouldn't we be then focused on the economic potential which I calculate by the numbers you used is about $600 million a year?

DR. FARUQUI: Yeah, the market potential was what would occur in the absence of a regulatory strategy. Economic potential is the relevant number to look at from the point of view of statewide benefits.

In the afternoon presentation I actually have a few numbers along those lines that I'll get into. But, yes, that's the correct number to focus on.

ASSOCIATE MEMBER GEESMAN: Thank you.

MR. BLEES: Excuse me. Chairman Pfannenstiel, let me just follow up with one additional brief comment because you mentioned both the appliance and the building standards. This may well have come up earlier before I arrived.

But I think it's important to recognize that a broad, thorough demand response regulatory approach may well require, from the Energy Commission's point of view, not only load management standards, but also potentially appliance standards and building standards.

For example, the Commission might decide now the most effective way to achieve its goals is to direct utilities to carry out various programs through the load management standards. To require new construction; to have various demand responsive features. And, for example, to require that certain types of new thermostats sold in the state meet an appliance standard that would require them to have certain types of features, controls to allow the best use of demand response programs.

PRESIDING MEMBER PFANNENSTIEL: Thank

you. Other questions here?

MR. TUTT: Just one. In terms of the difference or the similarity between the appliance and building standards and load management standards, is there any difference in our ability to enforce those standards, say the rate design standards?

MR. BLEES: There are some differences at the point where the rubber really meets the road. I think in terms of when the decisionmakers are considering the Energy Commission's general authority to adopt load management standards, they should feel comfortable that there is enforcement authority in general.

The building standards are enforced by local building departments through the mechanism of building permits. The Commission can take over enforcement, but only if it makes a finding that a local building department is failing to adequately enforce the building standards.

The appliance standards apply at the point of sale. So the Commission can go after retailers who are selling noncompliant products. And the Commission can also take enforcement action against manufacturers who fail to certify to the Energy Commission that their products are in compliance with the standards.

The load management standards are utility programs. So, the point of enforcement, if you will, would be the Commission making sure that the appropriate utilities are carrying out the actions prescribed in the standards.

But the utilities would be under a legal obligation to carry out the standards adopted by the Energy Commission.

ASSOCIATE MEMBER GEESMAN: Jonathan, or any of you other archivists, am I correct that the Energy Commission actually suspended the load management standards at some point in the 1980s? And as a consequence we presently have no such standards currently in effect?

MR. BLEES: I'm sorry, Commissioner Geesman, I do not know.

ASSOCIATE MEMBER GEESMAN: Thanks.

MR. BLEES: I do know that the standards are still on the books. They appeared in print. Whether there is some sort of a suspension clause, I don't know. I will find out for you.

PRESIDING MEMBER PFANNENSTIEL: Any other questions from the dais? Dave, you were suggesting that we might want to open it to the public and see if there are questions of this panel.

Barbara. We will need you to come up to the mike and identify yourself for the record, please.

MR. HUNGERFORD: And I'll just state for the record that we are running a little bit ahead, fortunately, and so we have up to 15 minutes to do this.

PRESIDING MEMBER PFANNENSTIEL: There should be a green light; make sure the green light is illuminated.

MS. BARKOVICH: I don't see a green light but you can hear me, so I guess that's what counts.

I wanted to make a point. There was, I think, a comment made about a cost effectiveness test for the standards and the cost of new capacity. For those of us who have been around much too long, and the Chair and I will remember some of this very personally, there was a major change in economics that occurred from the late '70s and into the '80s, which is that after the passage of the Natural Gas Policy Act of 1978, at the same time as PURPA, as natural gas prices went up and were deregulated over time, gas prices really went up.

So the price of energy, as it was to capacity, went up substantially. And then in the mid '80s went down substantially. Which greatly affected cost effectiveness analysis.

The other thing that happened is in the late 70s there began to be capacity shortages because of delays of the online dates of the nuclear plants. So that there was a lot of pressure on capacity. There were legislative hearings about capacity shortages, et cetera.

After the passage of PURPA and the implementation of the standard offer contracts for cogeneration and renewables, a lot of capacity came online during the early '80s, and early to mid '80s and on, even before some of the nuclear plants finally came online.

What happened at that point was that we went, as somebody mentioned, from a shortage of capacity to an excess of capacity. Just strictly for historical purposes, for the purpose of valuing capacity from that time forward, the Public Utilities Commission developed something called an electricity reliability index, which basically derated the value of capacity consistent with the existence of an excess supply.

If that was applied to the economic analysis in terms of cost effectiveness you would have had two things happening. One is that energy costs were going down; and two, the capacity price was derated, which also would have been relevant.

These two factors also significantly influenced the pursuit of energy efficiency programs because of the decline in the costs associated with those programs.

So, I could go on at great length, having been much too present. But that was the context.

Now, those things have changed again. But in the environment of the second half of the 1980s those were major considerations in both those areas. So that's just for your information.

PRESIDING MEMBER PFANNENSTIEL: Thank you very much. Some of us remember it well.

Other questions?

MR. HUNGERFORD: Are there any on the phone, Margaret? Any questions from the -- all right.

PRESIDING MEMBER PFANNENSTIEL: Now I want to thank the panel a lot. Ahmad isn't going anywhere until later this afternoon, but I think that understanding the context of load management authority and history is going to be very valuable as today's Commission tries to decide how to use -- whether to use its authority going forward.

Clearly times have changed, technology has changed more than any of us can possibly describe in the 30 years from the swimming pool pumps timers that Roger described, to what's available today.

And so we're really struggling with how to use this in the situation we face now. So, thank you, all.

And back to David and we will, I guess, hear about tautology now --

MR. HUNGERFORD: Nicely set up transition, Commissioner. We're fortunate to have Ron Hofmann and Mary Ann Piette with us from the Demand Response Research Center. And they've prepared a short presentation on the current state of demand response enabling technologies.

And as soon as I pull this up we can get started.

MR. HOFMANN: Good morning, Commissioners and Staff. My presentation this morning will try to give you a brief history of what's been going on since the energy crisis in the way of technology.

Commissioner Pfannenstiel, you're absolutely right; in the last 30 years not only has the technology changed, but the paradigms have changed. And this may, in the long run, be a key issue going forward.

So, I guess my main message over these 12 slides is that DR technologies exist, and they're becoming less expensive and more powerful. And so in terms of policymaking, you should not be concerned about the existence of technologies. There are cost effective technologies today, and it's only going to get better.

The issue is is that demand response is not about widgets. Demand response is about systems. It's about signaling widgets and having them respond automatically in some paradigms. But in almost all paradigms it involves systems.

So, what's needed are standards that relate to infrastructure that accommodates all the stakeholders' requirements and facilitates evolving demand response and energy efficiency policy.

And I put in red here what I consider to be sort of the bottomline issue, which is the challenge is to create a technology-neutral system integrated architecture -- that sounds like a mouthful, but if you think about it it's fairly straightforward -- that allows stakeholder systems to exchange information and evolve as requirements and technology change. What you don't want is to have to put in technology and then rip it out and put in new technology. You would like to think a little bit ahead and make sure that the technology you put in place has an incremental path to the future.

So this is a brief history on one slide of what's being done in the technology area through PIER. After the 2000/2001 energy crisis, PIER initiated a demand response R&D program. And those initiatives are bearing fruit already and I will get to that in a few minutes.

During this period we've held numerous workshops but I want to focus on three of them, which were all about system integration. And the system integration workshops led to the initiatives that Southern California Edison has taken in terms of their look at AMI. And as recently as just in the past few weeks I understand that this methodology of looking at system integration in a very rigorous way has now taken hold of things that are going on within PG&E. It may be going on in San Diego Gas and Electric; I'm just not familiar with it right now.

But it is characterized by stepping back and creating what are called use cases. And publishing those use cases publicly so that people can look at them and we can try to avoid the unintended consequences of deploying systems.

Typically when you deploy an energy efficient refrigerator there are very few unintended consequences. It really isn't a system. But the minute you have communications involved, the minute you have two devices working together to do something, you can get to unintended consequences.

so we had several system integration workshops in which we discussed this concept of use cases and how one goes about rigorously to avoid these unintended consequences.

There are two other things that are

underway right now, one of them that's on the slide, one of them that I forgot to put on the slide but I'll mention. 2008 Title 24 process began in 2005.

And there are two things that have come out of the demand response R&D effort. One is PCTs, which we'll talk about, programmable communicating thermostats. And something called global temperature reset, which came out of Mary Ann Piette's research at Lawrence Berkeley Laboratory. And both of those standards will be in place as part of the 2008 standards; and they will go a long way towards facilitating policy and things that you might want to do in the demand response arena.

The one bullet I forgot to put in is that late last summer the California Public Utilities Commission directed the utilities to include automatic DR in their planning, the auto DR concept in their planning.

Auto DR is not a program; it's a framework in which you can put programs and tariffs and it allows inter-operability. And I'll talk about that a little bit more in a minute.

So, what were the R&D initiatives that

were put in place in 2000/2003. Well, there was one that was called DRETD which really you can remember is just enabling technology. But don't think of this as the kind of enabling technology that you heard Ahmad talk about. This is one step below this. This is what makes the enabling technology that Ahmad talking about enabling technology.

And we put a very high bar for the research that was funded here. We wanted it to be disruptive. We wanted it to lower costs by not just 20 percent or a factor of two. We wanted to fund things that would make a huge difference in the ability for California to implement policy in ways that were absolutely cost effective. And at the same time we demanded that the functionality increase by a factor of ten.

This seems almost impossible except as I mentioned earlier, the paradigm has changed. And what we're really being measured against is an old paradigm in which it's very easy to get these very large order of magnitude improvements if you change the paradigm.

Another program we started was the Demand Response Research Center, and you'll hear a little bit more from Mary Ann later during the discussion. And there have been a number of projects that have been funded under the Demand Response Research Center. Most of them more in the one-to-three year timeframe, whereas the DRETD has been sort of a three-to-eight year timeframe.

And in the DRRC case studies have been funded so that the state would understand what others were doing, and whether or not we could benefit from others' experience. And also there was this auto DR framework that was developed, which I will show you in a few minutes, in which we can leverage existing technologies.

We were not trying to invent anything new. We looked around us and we said, well, what are other industries doing where they have changed the paradigm, where the electricity industry had not changed the paradigm. And we've tried to leverage those technologies. And I'll talk about that a little bit later.

And finally, there was the third leg of this stool was to focus on Cal-ISO needs.

So, what are the policy drivers for this R&D effort in the technology. There was a demand response OIR, a joint CPUC/CEC demand response

OIR, which is now closed; and has been replaced by something else.

But during that OIR there were three working groups. The two key working groups, working group two and working group three, focused on facilities that were above and below 200 kW.

Now, I'm hoping that that process, and in particular working group three, the process they went through will now be replaced in the future by a more rigorous systems process that will not get us into the problems that we're into right now with AMI.

And those problems are that if you go back and look at the decision and you read what is in there in terms of AMI decision, I think you will find it to be ambiguous.

When you're talking about systems ambiguity leads to the kind of result we've had over the last few years where everybody could interpret that decision in their own way.

The good news is that all the utilities are now starting to use use-cases; they're starting to converge on a common idea that will eventually satisfy what was in that decision.

The other policy drivers that we used in the demand response research and development program were the Energy Action Plan and the IEPR for 2005. And I think the key issues here are shown on this slide which are just that we were focused in on what did we have to do to insure price-responsive demand response in this program.

We knew at the time we couldn't do it by 2007, but there's no question now that the technologies that are coming along can easily match that and maybe even get larger numbers, depending on how they're deployed.

So, in support of policy there have been basically two major initiatives that are starting to bear fruit right now. One of them is auto DR. And auto DR is a framework that allows the utilities to actually operate multiple programs and tariffs out of the same signaling infrastructure. So that if they start with a program and it's not bearing fruit they don't have to change the infrastructure to change the program, or to change the tariff.

The signaling infrastructure attempts to include all the stakeholders. It attempts to leverage existing communication infrastructures. Nothing new is being invented here. And it attempts to use existing capabilities within the consumers' loads, within building loads.

And the other initiative is what we call the generic PCT, programmable communicating thermostat. This is taking the standard programmable thermostat and giving it communications interfaces that will allow it also to be part of a bigger system, a signaling system for example.

So, developing standards for inter-operability that can evolve incrementally over time as technology develops and is deployed is our major goal. And both of these initiatives attempt to do this. And, by the way, we are now in the process of harmonizing both of these infrastructures so that they are essentially the same.

So, just quickly, I'll tell you what auto DR is. Some of these words might be technospeak, and we can answer questions during the question-and-answer period. But those of you who are familiar with the client-server model, the current infrastructure for auto DR is what's called a publish-and-subscriber client-server model.

There is a common architecture for vendors, aggregators and system integrators. It's published openly. It's a standard platform. Again, words like architecture and platform have very distinct meanings in the information technology world.

For implementing time-differentiated tariffs, demand bid and other utility programs including integration with energy efficiency initiatives. And what we're trying to do is promote inter-operability transparency in standards by putting auto DR out there.

Auto DR is not a program. I said that before. I just want to repeat it just to make sure everybody understands that. But it can accommodate programs that exist within the utilities; it can accommodate policy; and it can accommodate things like time-differentiated dynamic tariffs.

So I'm not going to spend a lot of time on this picture, but I have one message with this picture. And you will see a very similar picture for PCTs.

If you look -- I guess my thing isn't working -- if you look at the vertical dotted line, that's the message here. In terms of policy, policy should be the what and not the how. The how should be left up to the vendors and the people who are going to buy the product.

But the what is very important. So one question of what that needs to be answered is where is the dividing line to where the utilities' domain ends and the consumers' domain starts. And we picked one picture here for auto DR. But this is open for policy. Policymakers should ask themselves the question, how far does the utility reach into the consumer domain.

And so a picture like this which has the auto DR structure in it, which we hand out to technologists who understand this picture, we have made an assumption about where that is based on the consumer choice issues that we've heard around the Commission for the last five years.

PCTs, even though they are focused on loads under 200 kW, they basically try to do the same thing. They try to set up technology and an infrastructure that allows demand response to work.

So in the PCTs specification we used a standard programmable thermostat and we added well-defined interfaces. So that we could receive at the thermostat, a standard thermostat that you're familiar with, price reliability and emergency signals, notifications and allow the consumer to have some choice about how they respond and what actually they buy.

And I think the biggest message that I want to leave you with in terms of the PCTs is not so much is technology, but when this process started the old paradigm dictated that the cost of these types of devices was in the $300 to $400 range. This is well documented.

There was a workshop that actually looked at cost effectiveness. The cost effectiveness work that was done by E3 set the hurdle at $150. But the PCTs that are coming out of the PIER-funded program right now have bill of materials cost of $20.

And there's one manufacturer that has already built one, and I can show you a picture if you're interested, that could be available at Home Depot in the very near future. And its price would be under $100. And that's its first price. As volume went up and competition developed, the price would get less.

So the message here is that in changing the paradigm the price dropped dramatically. With new technology that we're developing under DRETD that bill of materials is going to go from $20 to $2.

And now the question is, how do you, as policymakers, want to package this; and how do you want to use it. The stuff will be very powerful and it's just a few years away.

So, here's another one of the pictures that I talked about. You'll notice it's a vertical line, again. That's really the issue here is that vertical line.

If you look over on the consumer side you will see things like Gateways. You've heard that in the discussion earlier today, that Gateways were used in the ADRS program. The ADRS program, at the time of its paradigm and its technology just a few years ago, had costs that were between $1500 and $2000 per home. In this particular paradigm, with today's technology, not tomorrow's technology which is just a couple years away, but with this paradigm you can get essentially the same advanced technology for a couple hundred dollars, not a couple thousand.

So, again, very important to understand what we have attacked and what we think we've achieved is a major shift in what it's going to cost you to get the policies that you want.

So, my conclusions are there are no DR technology barriers. There is technology today that's already cost effective; and in fact, more cost effective than the cost benefit analysis said it had to be.

What is required is a statewide DR signaling infrastructure. And I don't mean that physically. I mean what has to be decided is what you want. What kinds of signals do you want people to have.

There are existing communications infrastructures that can handle this today. You do not have to invest in the infrastructure, per se. But you have to determine what it is you'd like to signal to people so that their devices can automatically act as their proxies to do the things that the state needs to lower its peak loads.

The challenges to establish a system that is simple so that consumers don't have to worry about it. It's almost invisible to them.

And low cost. And yet it meets your needs in terms of state policy.

Thank you.

PRESIDING MEMBER PFANNENSTIEL: Thank you, Ron. Mary Ann, did you have comments?

MS. PIETTE: Yes, thank you for the opportunity to speak with you today. And I want to thank the PIER program for the continuing support for the Demand Response Research Center.

I wan to just give you a quick update on the automated demand response project. I'm sorry, my mike wasn't on. I hope you heard me. I'll repeat a few of my words quickly.

Again, I want to thank you for the opportunity to speak with you today; and thank the PIER program for continuing to support the Demand Response Research Center.

The automated Demand Response Research Program is in its fifth summer of testing. We're working with all three utilities this summer. And we've worked with about 45 buildings over the past few years. For many buildings there's no hardware needed, and we can put in software with existing systems that can listen to signals for demand response over the internet.

For some buildings we need to retrofit the building with a box that receives the signals and then communicates with the energy management system. We are starting to do this in industrial facilities, as well. So many industrial facilities have control systems that can also receive common signals and execute preprogrammed strategies.

So while Ron talked about the capability of existing technology, there is a significant learning curve at the end-use facility about choosing a strategy to take a response to the signals that come in.

So, to participate in demand response program, whether it's a reliability program or a price-response program, there is a set of decisions that have to be made within the end-user site on what they're going to do.

Typically we do a cooling strategy modification or a lighting strategy modification, and we're looking at many industrial facilities and them making small changes in HVAC, lighting or maybe even process load control.

We are also sending signals to aggregators. So the technology we're developing is interoperable with aggregators and with the ISO. And we're exploring interoperability with the PCTs.

So the technology, we're making good progress in trying to come up with a common information model so that the signals going out are very clear to people, and we can automate participation in demand response programs.

So, I'll keep my comments limited to that, and I'll answer any questions you might have.

PRESIDING MEMBER PFANNENSTIEL: Thank you, both. Questions? Commissioner Bohn.

COMMISSIONER BOHN: In the process of developing or testing the technologies, have you developed anything or know of anything that talks about what consumer choice is in any kind of categorized fashion? That is to say, if my income is $20,000, is there an expected series of choices if I run a chemical plant, my expected choices are?

Do we have any knowledge in terms of what that is, the other side of all of this technology stuff?

MS. PIETTE: One interesting way to

think about the industrial facilities is we've had interruptible programs where people do very very large sheds very infrequently. And essentially what we're considering is doing smaller sheds more frequently.

And we do find a high variability in how willing a industrial site might be, depending on the kind of process loads. If it's a seasonal agricultural load, for example, and the tomatoes are being harvested, they're not going to do anything during that time.

So, we don't have sort of a framework to answer your question. But we have a general knowledge about that it's very specific to the process in the industrial facility.

MR. HOFMANN: I'd like to add to that and say that it's highly variable. And so the choice of the technology that we've been looking at is to deal with the variability and not try to fix it to one particular point of view.

So, at one extreme, for a homeowner, who basically just says I don't want to be bothered with any of this, we have research going on at the University of California in which a thermostat learns your behavior.

You set your preferences in terms of what you want, in terms of your bill and your comfort level. And you can just adjust a slider; this is a logical slider; doesn't have to be a physical slider. But it is your proxy and you have an override button.

And at least at that extreme people don't even care about their thermostat. They don't want to know about it. But they don't want a high bill. So we have to create a proxy that is not necessarily tied to your wall. Might be part of a remote like you have for your tv.

We're trying to look at technologies that will allow for variability. And we hope that the marketplace is very robust and it will adopt a variety of products so that people can get what they want.

PRESIDING MEMBER PFANNENSTIEL: I may talk a little about the PCT. I know we've been working on it for a number of years. And the concept behind the work we've been doing so far has been to put it into the building standards, and new buildings equipped with a programmable communicating thermostat.

And the challenge, of course, is to make sure the technology is there and that it is cost effective to do this.

Now we have the technology pretty well developed. So I actually have three questions. One is, is any manufacturer picking up on it and ready to produce it? And if not, is it a chicken-and-egg? Do we need to build the market first?

The second is you mentioned, Ron, you through it was going to be $100 first cost, and perhaps would be able to drop. But, do we -- is that based on having talked to manufacturers about where that might be?

And third is, as I said, we've been looking at it in terms of the building standards in terms of new homes. What if the Energy Commission decided, under our load management standards, to require every home in California to have a PCT, existing homes as well as new construction?

I assume that this device doesn't really even exist at this point, and so trying to think out that far is several years from now? Is that the kind of timeframe we'd be thinking about?

MR. HOFMANN: A device exists. May I show you one? Or do you care?

PRESIDING MEMBER PFANNENSTIEL: I'm not so interested in prototype as in the --

MR. HOFMANN: No, no, --

PRESIDING MEMBER PFANNENSTIEL: I care less about you manufacturing it than --

MR. HOFMANN: Not us, not us. I can show you one manufacturer who is the main manufacturer for Home Depot. The device actually exists. It actually works.

PRESIDING MEMBER PFANNENSTIEL: Okay, that answers my question, thank you.

MR. HOFMANN: And that's the manufacturer, it's Golden Power Manufacturing out of Hong Kong. It's actually owned by a company in San Francisco.

Their first device out of the box was far more innovative; it has more features than our minimum PCT. But it has the PCT concept in its subset. So it exists. And there's a beautiful picture I could show you offline if you'd like to see it.

You can actually hold it in your hands. One has been offered to Art for his desk soon, and there's a run being done in China right now where there will be several that will be built and handed around. So it exists.

$100, 99.95 was what I was told by Tim Simon, the CEO of the company. That's what it will be out of the box. He expects it to be 79.95 at Home Depot.

I can tell you, because I was a manufacturer, I can tell you that is the retail price. If you wanted to go with his current costs and go to a contractor price, it would be down another $10, $20 or $30 at the contractor price level.

There's another manufacturer just down the street here who is building the second one. It should be ready for you to hold in your hand at the end of June. And that's RCS, Residential Control Systems. They've done a lot of work with PIER.

And so it's real. It is absolutely real.

Now, a calculation that I did that you might want to think about, is at these prices you basically could give everybody $100 plus $50 to have a professional installer put it in.

They could buy a more expensive one, give them $150. And you could show a hand calculation very quickly that that's pretty much equivalent to a two-year payback of capacity costs. But those are just one time. Whereas capacity costs are year after year after year.

So, in terms of the building standards, to invoke it for everybody, it's something policymakers should think about. It has the ability to have -- and I'll use Ahmad's words -- it has great technical potential.

Our experiments both in the lab and with the statewide pricing pilot shows the technical potential is extremely high.

MR. TUTT: You discussed technologies that cover one of the three areas that load management centers cover. Are you doing any research on rates or storage of the other two areas?

MS. PIETTE: Yeah, the Demand Response Research Center has a new project to look at, the history and the status of dynamic tariff design; and Ahmad Faruqui is our contractor.

So it's a project that's just getting started and it involves corresponding with the PUC and the different utilities on what rate designs might look like in the future.

MR. HOFMANN: On the storage side we aren't doing any, as far as I'm concerned, on the demand response side we're not doing any storage work. But you might want to talk to Mike Gravely, as PIER does have a very robust storage program.

PRESIDING MEMBER PFANNENSTIEL: Further questions? Yes, certainly, Andy.

MR. CAMPBELL: Ron, another question related to the PCTs. So what role do you see -- in what areas, in terms of developing this system, do you see the policymakers, this Energy Commission, PUC, having an important role in sort of facilitating that kind of PCT --

MR. HOFMANN: So the big problem is sending the signals and the infrastructure for that. And what we've shown in the PCT is that the signals can come a variety of different ways. And we picked one that we knew would be around for the next 20 years and is extremely cheap. The system is called RDS; it's in cars today. It's called radio data systems. It's what shows what's playing on your channel on your LCD on your ratio if you have a GM car.

Let's just take that as an example, and I'm not promoting it. That's not my reason for describing it to you. I'm just saying it's just one thing.

The question is who maintains the operational aspects of sending the signals. The system already exists. The hardware already exists in FM stations all around California and it will be 100 percent in all stations within two to three years. That's what the radio industry says. It actually covers the state already with the stations that have it, already.

So the question is how do the load management standards support an annual budget for somebody to maintain the information that gets sent out. So they would have to coordinate with the Cal-ISO, the IOUs and other stakeholders in getting these signals out.

The IOUs would have certain types of pricing reliability signals that they would want to send. The Cal-ISO might want to send different signals, and they might want to send them through the utilities. So somebody has to sit down and figure out how is the annual cost of maintaining that system for sending information. How is that paid for. So that's one of the questions.

I'll give you some good news, I think

some good news. RDS, even though it'll be around for the next 20 years, I don't think has to be around. The utilities have some very robust ideas about doing two-way communications for meters and other systems. I think that will probably swamp the RDS system over time. The RDS system is a stop-gap for the next five to ten years.

Also, there's one other thing. I talked to Microsoft recently. TCPIP, which is normally thought to be used only on big computers or laptops or whatever, they have working on watches now. So it's just a matter of years where I think TCPIP becomes the standard protocol for everything.

And getting these signals from the internet, like Mary Ann does in auto DR, will be able to happen in the home, as well. Whether or not you have a DSL line. Today we can't do it because not everybody has a DSL line.

Does that --

PRESIDING MEMBER PFANNENSTIEL: Further questions? Yes, Art.

COMMISSIONER ROSENFELD: I'm just going to say that I think the most important issue that's come up today is precisely your question, Commissioner Pfannenstiel.

Title 24 handles 100,000 almost a year, major retrofits might be another 200,000. It's very small. We, of course, addressed this issue when we had our Title 24 conversations. We want to see universal PCTs.

We started this game a couple years ago when the reality that Ron Hofmann is proud of, justly, now didn't exist. We weren't about to talk about this, but for the next set of Title 24 standards there's lots of discussion of universality.

COMMISSIONER BOHN: Ron, can I go back just for a second. You said the most, if I remember your statement accurately, was the most difficult decision is who to pay for it. I don't think that's a difficult decision. Somebody can pay for it.

I guess a question where maybe you know the answer, or maybe there isn't any answer at this point, or maybe somebody else knows the answer, is what's the most effective and reliable locus for that information to be managed from, if I can dangle my prepositions.

MR. HOFMANN: Unfortunately I don't know

the answer to that. It's not a technological problem from my point of view.

I think I would talk to people like John Gooden at the Cal-ISO in terms of what their needs are, as a first step in developing what I call use cases for what you're trying to do.

But I don't know how that -- I really don't know the answer to that.

COMMISSIONER BOHN: So, from a technology point of view, you're indifferent? It's just a question of who can maintain the reliability of it, and the technology.

Bur relative, from your perspective, the technology doesn't care.

MR. HOFMANN: It does not care.

COMMISSIONER ROSENFELD: I learned most of this from Ron so I'm just repeating from dais. With respect to Commissioner Bohn's question, I think Ron makes the one-way communication, the RDS communication, sound a little harder than it is.

I mean he has quoted to me phone calls with RDS in which they can cover the state for $5 million a year. Which, by your standards, is pretty small.

And I forgot the second comment I was

going to make. Sorry.

PRESIDING MEMBER PFANNENSTIEL: Anything else? I want to thank this panel. They have helped us see what we were hoping was there, which is that technology if not the problem, and is part of the solution

With that, why don't we break now for lunch; come back at 1:30 and have the next step on what we do now. Thank you.

(Whereupon, at 12:05 p.m., the workshop was adjourned, to reconvene at 1:30 p.m., this same day.)

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AFTERNOON SESSION

1:37 p.m.

PRESIDING MEMBER PFANNENSTIEL: If people in the back will take a seat I think we can get started. David.

MR. HUNGERFORD: All right. Thank you. We are going to move ahead on our afternoon agenda. The first thing we're going to be doing this afternoon is we're going to -- Dr. Faruqui is going to talk about the second half of the whitepaper that's the subject of this workshop. And he will be talking about some ideas, not specific proposals, but some conceptual possible ways that the Energy Commission could implement a load management standard.

And the purpose of these scenarios is to open up discussion on the issues surrounding the Energy Commission opening load standards proceedings and creating loads management standards. And we want to avoid getting into any kind of detailed argument about specific elements of the proposals, because any such proposal would be fully vetted through a public process. And so the idea is to go after, to talk about the general ideas rather than the specifics.

And then following that we'll have a panel discussion with some invited guests representing the investor-owned utilities and the publicly owned utilities to get their perspective on what's going on in today's workshop, and to get some issues that need to be considered and thought about, if the Energy Commission decides to move forward with creating some newer load management standards.

So, with that, I'm going to pass it off to Dr. Faruqui, and we'll begin our afternoon. And if we move quickly we may finish within a reasonable amount of time and get out a little earlier. So.

(Pause.)

MR. HUNGERFORD: One more element. There will be an opportunity for public comment at the end of the meeting.

DR. FARUQUI: Thank you, David. So this session in the afternoon is a bit of -- you can think of it as a thought experiment, a mental journey in which we need to imagine a few alternative futures. And the purpose is really just to stimulate your thinking, not necessarily to advocate these specific standards as being the mechanisms that would be put forward by the Energy Commission.

As David noted earlier, I'm going to repeat that. The standards, themselves, will have to go through a rulemaking process where their pros and cons would be debated; their cost/ benefits assessed; and every party would have an opportunity to advise the Energy Commission of its viewpoint before they will be adopted.

So this is, you know, just an imaginary exercise. This is the other part of the mind. And we have been led to these three standards after having had discussions over the last month with several of you in the room and some of your colleagues who are not in the room.

We took a good hard look at the opportunity space for load management. We looked, of course, at what the utilities currently have in their portfolio. We looked at what was done back in the late '70s and early '80s.

And then we came to the conclusion that these three were good strawman candidates or proposals. So that's the genesis of how we arrived at these three.

The first one is a dynamic pricing

standard. It would make default dynamic pricing tariffs, the default tariff for all customers in all classes. And it would apply to investor-owned, as well as publicly owned utilities. That's the concept.

The second one would capitalize on the success of the PCT device, and make that standard technology for all residential customers, not just the ones in new buildings but in all buildings in the state.

The third one takes on the automated demand response concept that both Ron and Mary Ann talked about, and makes that the standard technology for all CNI customers.

So I want you to take 30 seconds, and before we plunge into the details of the standards, just engage in this multiple choice question. What would be the impact of these three standards. That's the question. None; small impact; moderate impact; and large impact. Those are the four choices.

UNIDENTIFIED SPEAKER: (inaudible)

DR. FARUQUI: Good one. Okay, --

(Laughter.)

DR. FARUQUI: -- how many think it would

have no impact? Okay. So clearly there is something of value here. There's something that will have an impact. I guess the whole question is what will be the size of the impact.

So to get a sense on the size of the impact we have done a few calculations. The first one is we tried to lay out a future without the standards. In other words, a continuation of the business-as-usual scenario.

In that scenario, based on the market potential and further issues and what-have-you, we think a 2.5 percent peak reduction might be achieved. That's over and beyond the 2.2 percent currently in place.

And if that were to happen it would represent over a billion dollars in savings in the next 20 years. You know, you can play with the assumptions, you can change the numbers around. That's what I'm saying currently in this exercise we have defined as our baseline.

So that's kind of the natural momentum of things will produce this. And how did we get this number? Well, we used the same methodology as I had described in the morning presentation. The same sector shares, the same technology mix.

We assumed statewide deployment of AMI. We assumed the programs are opt-in. And we gave it a 20 percent participation rate. In the morning we had a 40 percent participation rate. We dropped it to 20 percent because 20 percent, as you look around the country, you look, for example, at what happened in Arizona with the Salt River project and Arizona Public Service, with their time-of-use rate program, they have achieved a 20 percent participation rate after ten years.

So, very well designed, aggressive programs, we said, okay, let's use that as a role model for this particular calculation. And so that's the 20 percent number. That's how we get the 2.5 percent reduction.

Since this is a naturally occurring evolution we do not assume that customers are equipped with the enabling technologies. Okay. So keep that in mind; that's sort of the point of reference.

And now I will introduce the three new strawman proposals one by one and I will layer them one on top of the other. So the first one I'm bringing in, which I think is the key to everything, is the dynamic pricing standard.

So if that standard was to be adopted what would be the likely results. So, first, let me tell you what the assumptions are. The assumptions are that dynamic pricing is the default tariff for all customer classes. It's not mandatory, it's default, with an opt-out. Okay. That's just how we conceive of the scenario. So 80 percent stay and 20 percent opt out, to use numbers that have been used b a number of parties in such discussions.

And we assume no enabling technologies are being offered to customers. So that will give us an additional 7 percent peak demand reduction. Incremental financial benefits of $4 billion.

This is without any enabling technologies being made into standards. This is just the pricing standard by itself. Okay.

And now we bring in the PCT standard, which applies to residential dwellings. And we find that if this is brought in incrementally on top of the dynamic pricing standard, then the average reduction in residential customers who have this technology is going to be 27 percent, using the results from the SBP.

And what this gives us is an additional

8 percent reduction in peak demand; and incremental financial benefits of $5 billion. It was a huge multiplier.

If you go back, this is the picture without the enabling technologies, 7 percentage points and $4 billion. You add the technology and you basically double the impact and the financial benefit goes from -- which was $4 billion here, rises by another 5. So you basically double both the numbers, a little bit more than double.

So that technology was, of course, for the residential class. Now we bring in the automated DR standard which has a smaller impact on a percentage basis than the residential PCT device. And we find that the incremental impact is another 2 percentage points, and the financial benefits rise by $1 billion.

So to put it all together, this graph shows in the very left side the voluntary dynamic pricing, no standards, just the market, you know, operating on its own with encouragement and incentives and AMI in place. With the 20 percent participation rate and so on. 2.5 percent reduction; $1.4 billion benefit.

Now you go to default dynamic pricing

and basically the extra benefit you get is by switching from a voluntary program to an opt-out program. And that's basically, you know, the magnification of benefits. No technology intervention has occurred, just the rules of the tariff have been changed.

Then you bring in PCT. Now, interestingly enough, PCT can be thought of at two different levels. When we were doing our report we were actually thinking of it as gateway systems, when we did this calculation. So the graph that appears in the report, you will notice we have put a plus there next to PCT at the bottom of the third bar. PCT plus. That's basically the gateway system.

So it's not just the PCT applying just to the air conditioner and the heating equipment. It's applying to all of the other uses. And I have run it both ways, so the next slide I'll show -- it is not in the paper -- I'll show you in a moment, obviously has a smaller number. And we will put that in to modify the final version of the paper.

So, if you stick with PCT plus for now, you get a 7.9 percent incremental impact and a

$4.5 billion number that goes with it. You bring in the automated DR, you get an extra 2.4 percent on the impact front, about $1.3 billion of the financial front. You add up all of those numbers and you get the bar on the right-hand side.

It's a stacked bar. The portion at the bottom is the naturally occurring effect. In other words, it is equal to the first bar.

And then the incremental effect of the standards is shown by the solid blue portion of the bar. And it's showing an $11.4 billion benefit, 20 percent demand reduction. So that's, you know, a huge magnification of the savings both in peak demand and financial benefits that is achieved through the standards.

Again, this is a visioning exercise. This is a conceptual discussion. The details of the standards will be fleshed out and so on. But if you take these numbers as talking points, this is the logical conclusion we arrive at.

Now, here is the adjustments. So I took the plus away from the PCT. This is just a regular PCT. And if you stick with the regular PCT the incremental impact, as you recall from the experiments that have been done, the smart thermostats, 27 percent, the gateway systems 43 percent, quite a huge difference there.

So we have gone back just to the pure PCT idea in this. You still have huge cumulative impact. So look at the bar at the very end. We're looking at $8.5 billion and a 15 percent reduction.

So, just so there's no confusion I'm going to just flip back. This is the chart that is in the report. Much bigger number at the end. Let's just focus on the dollar number for a moment, $11.4 billion. This number with the adjustment for the PCT took the plus away, is 8.5 billion. Still a very large number.

And I think the point I want to make, each of these numbers we can debate and argue, and they can go up and down. But the point is that the standards act as a huge multiplier to the impacts. The market impacts, by themselves, are very small. The standards are huge.

Now, in the back of your mind you might be thinking of the number I mentioned this morning about the energy efficiency programs, the naturally occurring was half, the standards were the other half. Here the standards are much more than half, at least in this conceptualization. Okay.

And clearly, you know, we can discuss this; we can go into the details; the numbers might move around, but the orders of magnitude, I think, are certainly, you know, interesting.

So, with that, I want to take a slightly more detailed look at each of these three strawman proposals. Again, you know, think of these as talking points, think of these as avenues for further discussion.

So what could be done in the standard on dynamic electricity pricing. You've probably seen those pictures of new buildings, you know, before the blueprint, before the building's constructed, there is the artist sketch. So this is kind of like the artist sketch, you know, it's just a very very rough sketch.

So what would be the intent of the standard. The intent would be to empower customers with choices over the timing of end uses. What's the alternative? The alternative is direct load control where there's a particular end use, let's say air conditioning, which is the focus of the program. Pricing is not fixed on one particular technology. So they have more choices on what things to move around, based on the value they attach to the different end uses.

Improved system reliability would also be a byproduct of this. And so that's the intent, is to provide choices to customers and to improve system reliability.

What are some of the provisions that we can imagine for this program. The provisions would be, number one, default dynamic pricing tariff at each utility for all customer classes.

Number two, the tariff would reflect the long-run cost of avoided capacity and energy. So that would be the challenge, is how to estimate those, how to capture those in the tariff, how to convey them in a simple manner to the customers.

What would be some examples. Well, we've all talked about critical peak pricing. That's certainly in the running. But you could also have the slight variation that we discussed at the last meeting, the variable peak pricing idea. And certainly, real-time pricing is not excluded in this concept. So those would be examples of dynamic pricing.

It would be up to the further details

when they are fleshed out. Maybe some of these tariffs would be made the default. The others would be options. Maybe they would vary by class. All of those are details to be examined and fleshed out.

The design of the tariffs would be revenue neutral. So it would purely be a rate design issue, as opposed to a ratemaking issue. Ratemaking would still be done based on other considerations. The question is how to design the rate, and that's why they would be revenue neutral.

Because these tariffs would represent a different way of sharing risk between the supplier of power and the customer, people who go on the tariff would be given a credit equal to the hedging premium that is implicit in the fixed tariffs. So it would be revenue neutrality coupled with the credit for the hedging premium.

I believe in the last workshop the express Commissioner Rosenfeld used was we have to sweeten the deal, we have to make it interesting to the customer. And the hedging credit would be an example of a cost-based mechanism for sweetening the deal. It would not be a subsidy.

It would be still cost-based.

The bills would be provided to customers in a transparent manner so that they can calculate what are the incentives from shifting what are the costs of not shifting.

So all of those would be part of the standard. And each of these points, as you can imagine, could be debated for hours, could be the subject of workshops and that certainly would need to occur if the standard goes down the path of becoming the real standard at some point.

MS. McNICOLL: Do you also (inaudible) --

PRESIDING MEMBER PFANNENSTIEL: I'm sorry. If you have questions, either you need to wait until the question time, or you need to come to the podium. This is being recorded and we can't hear you.

DR. FARUQUI: Did you want to come to the podium, Susan?

MS. McNICOLL: Sorry. Susan McNicoll from PG&E. Ahmad, I just wondered if --

COMMISSIONER ROSENFELD: Your mike's not on.

DR. FARUQUI: The button, that is the

push button.

MS. SPEAKER: It actually is on; you just have to bring it a little closer to you. Here we go. There, this one's on.

MS. McNICOLL: Hi. I just wanted to -- Susan McNicoll from PG&E. Just wanted to know if you embedded in here the assumption that AB-1X would not exist in the rate design on the dynamic pricing?

DR. FARUQUI: Good question. The question is whether AB-1X is no longer being viewed as a constraint.

Well, the way this tariff design was laid out, in the document we had some language edits that were proposal on how AB-1X could be modified to accommodate these. And it was just a suggestion.

But certainly it will pose a barrier unless that language is modified the first two tiers, several of you know, would be excluded from default pricing on a critical peak pricing basis.

A rough estimate of the first two tiers, the amount of energy that is embodied in those first two tiers is somewhere between 60 to 70 percent. And that would be a very large exclusion.

So, as part of the story line here, what we had suggested again as a strawman, is that the intent, perhaps, of AB-1X was to protect the customers, use it in the first two tiers. However, the way they wrote the language, they froze the rates in the first two tiers.

And a modification was suggested which would be that instead of freezing the rates, the customers bill from the first two tiers would be protected. And so it would be no higher, but could actually be lower.

And so if the new rates come in, into the first two tiers, and the bill is computed using the old and the new. And the new is actually lower then there would be no problem in the modified AB-1X language, if you will.

Again, we know we went out on a limb a little bit. There are more than one way of doing it. But certainly we have assumed that it has been relaxed and accommodated to allow for this to happen for the residential class.

Among the benefits would be, of course, greater efficiency in the pricing of electricity. I quantified those benefits earlier. Elimination or at least mitigation of inter-customer intraclass subsidies that exist today between the peakier than average customer, which is the flatter than average customer. And an opportunity for many customers to lower their bills.

The amount of the reduction in the bill, of course, would depend on how much of a load drop that customer's achieved; what their load shape looks like; and what the specific tariff is.

Clearly, these lower customer bills, the amount of reductions would be modest. Nobody, you know, should expect the savings to be more than 10 percent for, you know, most customers. But there would be an opportunity to reduce their considerably higher bills in today's environment.

The cost side of this would be, of course, the cost of AMI, which is not covered by the operational benefits. That cost is by and large already being addressed in other proceedings, and may not be a factor by the time the standard comes up for discussion.

The implementation schedule would have to be realistic. Customers would be given time to adapt to the new pricing scheme. Perhaps the tariffs would be phased in over a two- to three-year period.

Maybe in the first year every customer would be given 100 percent bill protection, just so they can experiment with the rate. Maybe the protection would slide down over a two- to three-year period, and then after the third year, you know, they'll be unprotected.

Every customer would be required to stay on the tariff for one year, and opt out after the first year.

So those are some of the ideas that could be used to make the tariff politically acceptable. And that would certainly be a key issue in a tariff like this.

Of course, I forgot that I had this slide at the time that the question arose from Susan McNicoll. This kind of recaps a little bit of what we have already discussed. We all know AB-1X poses a barrier to the residential class.

In the earlier whitepaper we estimated across subsidies between customers in the first two tiers, and usage in the other tiers, as being between $3 to $11 billion, which is projected to keep on rising year after year.

The effects of AB-1X must be corrected

for dynamic pricing to happen effectively in California. There is an opportunity to begin a dialogue with the legislators, perhaps who wrote the original AB-1X, to identify the unintended consequences of the rate freeze; and not just unintended consequences that have historically occurred, but the ones that are likely to occur for a time horizon that some people say ends in 2015; and others say it continues till 2021.

I mean, if it continues to 2021, that legislation with a 20-year life would probably be without precedent in the history of ratemaking, where everything else changed, but the first two tier rates didn't change.

And then imagine what would happen to the rates once the freeze is lifted to those customers.

Okay, so that was the first standard, that was the first concept or strawman proposal. The second and third assumed that the first one already is in place. I don't think it makes a whole lot of sense to do these enabling technologies in the absence of some kind of dynamic pricing. Which is not to say that they couldn't be done. There still could be technology that could be exercised on a pure reliability basis. But its effectiveness can be multiplied enormously if they are coupled with the right pricing environment.

And I think that's sort of the message, at least implicit in this package, the portfolio, the three strawman proposals, that they are bundled around a foundation of having correct and accurate pricing.

Okay, so what's the story with the PCTs. The intent is to enable residential customers to achieve greater bill savings by automating their air conditioning systems and making it easier for them to respond. And as seen in the experiment you can get almost twice the savings if you have the technology versus if you don't. So you get larger reductions in peak demand. That's the intent.

The provisions, this is one scenario; this is, as I said, an artist sketch. California ISO perhaps would send a signal to the PCTs to raise the setpoint by 4 degrees during system emergencies or due to economic conditions or both. Okay.

In extreme emergency situations the PCTs which would normally have an override button would be disabled and signals would be sent on a day-of basis. There would be a limit on the number of times the PCTs could be dispatched per year.

Again, these are details, you know, this is one interpretation. A lot of different interpretations can be conceived. But this, at least, kind of makes it a logically internally consistent case.

The benefits potentially 1600 megawatts of reduction in peak demand, or $2 billion in present value terms. Impact would, of course, be a lot smaller if the PCT penetration is limited to new construction and remodeling. It could be about -- it could shrink by a factor of five, maybe factor of ten, depending on how rapidly new construction or remodeling are taking place.

On the cost side you use the number which Ron Hofmann mentioned earlier. He said less than $100, so I took that to mean $99 in this discussion. It may be a lot lower, but certainly a number in that range we are told is conceivable not just in the lab or in Ron's mind, but actually at Home Depot. So that's the PCT proposal, if you will.

The last proposal, which is automated DR. Sometimes in the presentation we have referred to it as auto DR, sometimes as automated DR. The only difference is automated DR is the more general term. Auto DR, I understand, is more like a brand name. So, you know, depending on which one you like you can use, just use that as the heading of the slide.

The intent is to enable the CNI customers, which based on the earlier numbers I showed you, represent approximately 60 percent of the peak demand. To bring those into the fold so that they can respond to higher prices and achieve the greater bill savings.

It will facilitate large reductions in peak demand if this auto DR is implemented through a standard.

In terms of the provisions, again we are imagining that the Cal-ISO would activate these systems. It could be a day-of basis, as stated here, for emergencies; or a day-ahead basis if it's basically an economic driver. So both modes are possible.

The benefits could be potentially 1500 megawatts of peak demand reduction valued at a billion dollars when offered in conjunction with dynamic pricing. Keep in mind, if it's not offered in conjunction with dynamic pricing it can still be used from a reliability perspective, but probably then could not be driven by an economic trigger on a day-ahead basis.

The costs, of course, would vary by type of facility. They would be more customer-specific than the cost of the PCT. In some of the literature we looked at we came across an average estimate of $800 per building with some additional operating costs. I just throw that number out there just to complete the story. I know there are experts in the room who may have a comment or two on the specific costs of that technology. But keep in mind, -- dollar per building is being applied to a large building, so the savings for CNI customer are going to be substantially higher than what you would expect from a residential facility. So even though it costs more than the PCT, it is also applying it to a much larger facility.

So, in a nutshell, what can we say about these three strawman standards. Well, to recap a little bit of the morning discussion, I would say there's general agreement that the experience California had with the load management standards, was positive. It stimulated discussion about ways to reduce peak demand that lasted beyond the standards becoming kind of inoperational. It led to programs that are still effective today.

The state has had a lot of success with building and appliance efficiency standards. And all of this argue that it is time to revisit the load management standards.

We have presented to you three strawman proposals which, at least in our opinion, present a compelling picture of large benefits that would accrue to the state were the Energy Commission to pursue its load management standard setting authority.

We focused on dynamic pricing and enabling technologies. Other options are possible. Those we felt were, if you will, the low-hanging fruit that is within the realm of not only technical feasibility, but economic feasibility.

And as Jonathan Blees argued, within the realm of legal feasibility, as well.

We've looked at day-ahead and day-of

deployment. We are assuming that the intent is to enhance the role of pricing mechanisms for managing demand and supply, a market-driven economy, as the Governor has talked about, is what California needs.

And to decrease the dependence on cash incentives, because not only are they expensive, they also create a sense of dependency that once you remove the cash incentives, the market is not transformed and it relapses back.

And that's it. Thank you.

PRESIDING MEMBER PFANNENSTIEL: Thank you, Ahmad. I want to make sure I understand one of your assumptions. On the PCT estimates you assumed that PCTs would be part of the building standards, and therefore would apply to new homes and new buildings and major renovations, not that they would be required for everybody?

DR. FARUQUI: Well, actually I assumed that they would apply to everyone.

PRESIDING MEMBER PFANNENSTIEL: Okay.

DR. FARUQUI: So what I did was I assumed that they would go beyond just the update of the Title 24, so as part of the load management standards they would apply to retrofit applications as well.

PRESIDING MEMBER PFANNENSTIEL: Okay. So every home in California --

DR. FARUQUI: Every home that has a thermostat today would be, you know, -- that would be taken out and the new one would be put in.

PRESIDING MEMBER PFANNENSTIEL: Thank you. Other questions?

COMMISSIONER ROSENFELD: I have a couple of small comments.

DR. FARUQUI: Yes.

COMMISSIONER ROSENFELD: First of all, your three strategies, of course, very very similar like 99 percent overlap with what we've been talking about for the last few years.

I would point out small differences. You say on -- I'll tell you which one --

DR. FARUQUI: Should I put the slides up?

COMMISSIONER ROSENFELD: You say on slide 14 that the ISO would send out a signal which would set up a thermostat by 4 degrees. What we built into Title 24 differs on that one line two ways.

First of all, the ISO doesn't right now

send out any signals for mitigation like that. It sends the signals to the utilities, but it's the utilities who would send out the price signal and tell you a day ahead of time, tomorrow is a critical day. So that's a small difference.

The other thing is this set up of 4 degrees -- that's a default which we specified from the factory. So you get your -- you won't get your new home and it has a thermostat in it -- set it, have a default of 4 degree Fahrenheit. But you can do any damn thing you want. You can reprogram that to zero degrees Fahrenheit or 8 degrees Fahrenheit, or anything you want.

We're not proposing that Pacific Gas and Electric tell you what your comfort temperature is. Fair enough?

DR. FARUQUI: Yeah, I see what you're saying. I guess all I would -- let me respond to both of your questions.

The first one had to do with who sends out the signals. And I just said, in this conceptualization we assumed that there would be some mechanism, either the Cal-ISO, itself, would send the signal, or it would notify the utilities through some protocol of communication between the utilities and the Cal-ISO that tomorrow is going to be a critical day; and it is time to notify the retail customers, the end customers. The load-serving entities physically could then be the ones that dispatch the signals. But the trigger would originate at the Cal-ISO.

I mean that could be perhaps a hybrid of what maybe you and I are talking about.

COMMISSIONER ROSENFELD: Sure.

DR. FARUQUI: Okay. On the second issue about the magnitude of the setpoint adjustment. If I understood you correctly, Art, you were saying that it would still be up to the customer. It would come with a default 4 degree setback setting, but the customer could modify it.

COMMISSIONER ROSENFELD: Exactly.

DR. FARUQUI: Okay. I guess if that was to be done, then the magnitude of savings would change. In all the calculations we have done, we have assumed a 4-degree, you know, setback assumption.

If some customers had zero, or some had 2, some had 3, then -- and some had 6, you know, the savings magnitude would change. The concept would not be affected.

COMMISSIONER ROSENFELD: I agree, except on a central value -- we figure 4 degrees for four or five hours is probably about what the average person would -- average homeowner would choose. So some would chose more and some would choose less, -- 4 degrees seems like a perfectly reasonable economic calculation.

So I'm not disagreeing at all with your estimate or what the savings would be. I am just trying to soften the impact. I repeat, I realize I'm repeating, but we don't want to get across the idea that your friendly utility is telling you what your comfort thermostat would be.

What it is telling you is you signed up for tariff and you're paying 70 cents a kilowatt hour on a hot day, and you can decide how you want to respond to that.

DR. FARUQUI: And the customers could also override this right. I mean, --

COMMISSIONER ROSENFELD: And the customer can override any time they want, yeah.

DR. FARUQUI: I know in some other jurisdictions some of the vendors are saying to the utilities, don't put a button on the device that the customer can easily push to override.

Make it difficult for the customers by having them call a phone number or go to a website.

And I think that's certainly an issue of how much customer choice do you want to provide to the customers. I mean it's sort of like a two-edged sword. Certainly choice is good, and maybe that's the best way to move forward.

The other viewpoint is some people are arguing -- I personally don't agree with this -- make it very difficult. Well, the more difficult you make it, the more "Big Brother" like it becomes. And it would create its own backlash.

I guess those are the pros and cons.

COMMISSIONER ROSENFELD: Sure.

PRESIDING MEMBER PFANNENSTIEL: Yes, Commissioner Bohn.

COMMISSIONER BOHN: I'm not sure I understand your participation rate assumptions. You talk about 80 percent and 20 percent in the first two. And then we talk about all residential customers are equipped with -- does the participation rate in these calculations need to differ? Or did you keep it constant? Or is it irrelevant? I'm a little confused as to we go 80/20 and 20/80 to deal with the opt-in/opt-out question.

DR. FARUQUI: Okay, -

COMMISSIONER BOHN: But then in these last two you talk about all residential customers and all CNI customers.

DR. FARUQUI: Okay. So there are a couple of different participation rates that we are talking about here. The first one is the dynamic tariff.

And we assume that everybody is moved onto the default dynamic tariff. For the first year everybody stays on it. At the end of the first year we assume 20 percent opt out. And so when we calculate the benefits of the dynamic tariff we are only calculating that for 80 percent of the customers. And we are initially assuming no enabling technology.

Then we come to the second standard which is of the PCTs. And we're assuming that every house in California has the PCTs. However, only 80 percent have agreed to stay on the default tariff. And so that impact is also for 80 percent.

And finally, the same thing applies to the auto DR; it's also only applying to 80 percent.

The numbers would basically be higher by another 20 percent if it was 100 percent application. So, you know, that's sort of the rule of thumb.

PRESIDING MEMBER PFANNENSTIEL: Other questions? Yes.

MR. CAMPBELL: Taking the PCTs, for example, I'd like to understand a little bit more what sort of conceptually the standard might consist of. Like who would be required to do what to whom in order to -- within the standard, itself.

DR. FARUQUI: Okay. So I guess there is a cast of characters here. There is the occupant of the building, themselves, either the tenant or the, you know, the building owner.

There is the builder or the contractor, you know, who's going to install the device. There is the utility or the load-serving entity. There is the Cal-ISO. There are the two Commissions and possibly the third-party aggregators.

I think that's the cast, that's the maximum cast, that's the potential of players, if you will.

I think of all of those players, the most critical ones are going to be -- the first decision is, sticking again with PCTs, the first decision is to actually put the PCTs in the houses.

And so I believe the Energy Commission, in this scenario, would pass a standard that says all houses in California will be equipped with PCTs.

And then somebody would be responsible for actually making those changes, a contractor presumably. As to who would supervise the contractor, and who would fund the installation of these devices and cover the labor costs, you know, I don't know. I think that's an important issue to be worked out. But there are certainly dollars involved and there are contractors involved.

And then the third -- so now we have the buildings, the technology has been installed. The question is of sending the signal. I suspect one scenario could be that the Cal-ISO triggers the event; notifies the load-serving entities. The dispatch the tariffs. And as they dispatch the tariffs, they also dispatch the PCTs.

That's one way of doing it. I think it all centers around the tariff. It is consistent intrinsically with the tariff. And because it's a statewide market situation I think probably the decision on whether or not tomorrow is a critical day would probably have to originate with the Cal-ISO. At least that's one concept that I had in mind. I'm sure there are other ways of doing it, but that would appear to be the least disruptive way of making it happen.

PRESIDING MEMBER PFANNENSTIEL: Other questions? Thank you, Ahmad.

DR. FARUQUI: Thank you.

PRESIDING MEMBER PFANNENSTIEL: Now I guess we hear from the utilities on your thoughts on how this will work.

MR. HUNGERFORD: All right. Well, thanks, Ahmad. We have invited those that would be directly affected by these types of activities we're talking about to lend some comments to this discussion this afternoon.

We've invited the three investor-owned utilities. And because the demand response discussion has often left the publicly owned utilities a little bit on the sidelines, and the

Energy Commission's load management authority does extend to publicly owned utilities, we've invited some representatives from NCPA, the Northern California Power Agency, to come. And also we have a representative from SMUD, who can help us sort of understand how these agencies -- or how these organizations might respond to these kinds of standards.

I want to be clear that because we're running these -- we've put out these scenarios that are sort of broad and don't have a lot of detail to them, there's not a whole lot for them to specifically prepare for this discussion. So it's going to be structured more as an open discussion.

Southern California Edison has prepared a presentation and we'll go ahead and let Edison go first. And then we'll have everyone come to the table and we'll turn up the lights and have an open discussion on a number of these issues. Some of them may have prepared remarks last night, some may have prepared some during the discussions today. I've seen Mr. Tomashefsky from NCPA making some notes today. And so we hope we'll have a lively discussion after that.

So, Larry Oliva of Southern California Edison is going to be delivering. And Russ Garwacki is with him. And I will see if I can open this up.

(Pause.)

MR. HUNGERFORD: It's not in my folder but I will get it quickly; my apologies.

MR. OLIVA: I'll go ahead and start --

MR. HUNGERFORD: Why don't you go ahead and start, thank you.

MR. OLIVA: Good afternoon, Commissioners and Staff. We're pleased to be here and to have the opportunity to speak with you today. We are very supportive of the effort to look at potential load management standards. I would like to go through just some comments that we had just looking at the document that Ahmad put together.

But generally I wanted to make some remarks that say that we have been in support of the Commission since the energy crisis. We continue to be supportive, and will be supportive if the Commission decides to take steps toward standards.

We are very enthusiastic about demand

response. We believe it is an answer to our need in California for providing supply to our customers. And with global warming and with all the issues with respect to environmental concerns, we think the time is now to keep pushing, and pushing hard with respect to demand response.

MR. HUNGERFORD: We do have the presentation up.

MR. OLIVA: Thank you, David.

MR. HUNGERFORD: Would you like me to slide --

MR. OLIVA: Page 2.

MR. HUNGERFORD: Okay. Would you drop the lights? Can you still see your notes, Larry?

MR. OLIVA: Yes, sir, I do. thank you. The CEC has initiated a number of successful demand response initiatives since the energy crisis which has set an example for the rest of the country.

And through that example there have been several initiatives now that have been taken, including AMI, at all three utilities. And enabling technologies that are being researched and put into place. And including all the work that's being done with respect to PCTs and smart thermostats, the pilots on those, as you know.

The statewide pricing pilot was a tremendous effort that the whole world has been looking at with respect to how to implement demand response and what the impact might be if you imposed, or if you used dynamic rates and enabling devices.

There is dynamic pricing that is enabled through our large customers and the meters that we have in place now, which is another initiative that's been undertaken, as well as the MRTU, which will help bring all these things together when that's implemented and we have real market prices that we can tie, for example CPP, or real-time pricing to those markets.

We also have the OIR on demand response measurement, cost effectiveness and goal-setting, which has been an issue in the past number of years, because there's been disagreements among the utilities and among the Commission and among other parties with respect to what is demand response really worth; is it cost effective; what should be included; how is it measured. And hopefully this proceeding now will settle those key issues and allow us to move forward.

Page 3. With respect to the three proposals that are in Ahmad Faruqui's paper, with respect to dynamic pricing, again we're supportive of that. It does allow us to design rates that are closer to our costs. Very important economic principle.

And our costs for our top 100 hours are very high. And it's not until we get metering that enables that time differentiated pricing that we can really reflect those costs to customers.

With respect to programmable thermostats and enabling technology, we know through our own load control program with A/C cycling devices that it's very effective, and provides significant demand response.

We proposed three years ago to the California Public Utilities Commission before the AMI initiative took hold, that we install what we called advanced load control, which was a similar type of program. It had advanced -- the intent was to use an advanced thermostat, because we believed in it. We think that's how to get customer adoption.

I mean cycling devices are fine, but not all customers understand how that impacts their comfort. Whereas a thermostat with a four-degree setback, or whatever setback the customer chooses, allows them to understand what their comfort level is and should encourage adoption rates.

And the third on auto DR or some technology that helps enable larger customers to participate in demand response through an automated means, or means that allows them to run their business and not worry so much about whether there's an event or not, will get much higher adoption than we have today.

We have pretty good adoption on some of our programs for large customers, but particularly in the below-500 kW class, customers are interested in running their business. And don't have staff or the time available to pay attention to their hourly energy costs.

So we're supportive of all three of these efforts. But an Edison presentation wouldn't be complete unless we expressed some concerns.

(Laughter.)

MR. OLIVA: So I just wanted to take an opportunity to go over a few of those things.

First, on demand and supply interaction, and I think this was mentioned a little bit earlier, that when there's over-supply or when there's enough supply then our cost of capacity or the cost of the alternatives is not very high. So the incentives that we could offer to customers is also not very high. And so they're not that interested in participating.

And there are supply/demand imbalances. And so, you know, there is a concern about how we are able to continue to provide cost effective programs when there may be imbalances with respect to supply and demand.

Despite not being mentioned today, reliability programs such as our A/C cycling program or the BIP program that we have provide significant megawatts of emergency load reduction. And we think that's important. The Cal-ISO thinks that's important. And I'm sure that will continue to be important in the future.

A third point which has already been discussed is AB-1X, and what do we do about that. In our AMI proposal we are strongly considering using what's called a peak time rebate, which is sort of a stopgap, a way to get around the AB-1X issue for the time being. It may not be the best rate; it may not be the best with respect to instilling permanent behavioral changes in customers. But it is a way to get around the AB-1X issue initially.

And it's a way to allow our customers to walk before they run with respect to dynamic pricing that with an approach that provides a carrot only. We may be able to get really good participation right off the bat with our AMI program.

The next point Commissioner Rosenfeld clarified for me, thank you very much. Because we were concerned about Ahmad's paper and other people have used the terms loosely with respect to Cal-ISO control of customer loads.

It's fine for the Cal-ISO to determine when an event should take place, but we really would like the ISO, and the ISO would like, us to control those loads. And so we just want to be clear on that.

COMMISSIONER ROSENFELD: We have to continue to gang up on Ahmad, right?

(Laughter.)

MR. OLIVA: That's right. He's too smart, I need more than one person to gang up on him.

Finally, we do have and plan to have a voluntary program with respect to the PCTs. So, when Title 24 is in place for the PCTs, new homes or retrofit homes, we plan to offer, unless there's another standard, we plan to offer those PCTs to customers so that they could enroll in the program.

And we would do that probably through a rebate type approach, where the customer could purchase a thermostat through a retail provider. They would get an incentive for installation. And once that is installed they can sign up for the program. And then we would communicate with that thermostat.

We think we can get about 25 percent of our customers to participate in the voluntary program. WE would stop new enrollments in our A/C cycling program at that time so that we would get customers on a PCT-type program.

And finally, the last page I just offer to you just for additional information on the current programs that we have so you can see that we have significant megawatts already enrolled in demand response.

However, with respect to price response we do not have very many megawatts enrolled. And it's an issue for us. We're trying to get more. We would like to get more. We're a little bit thwarted, so to speak, by the fact that we have a large amount of customers enrolled in our reliability programs. If those customers were not enrolled in the reliability programs, they would more likely enroll in our price-response programs.

So, as long as we have reliability programs taking up some of those customers, it makes it a little bit more difficult for us to get price-responsive programs enrolled.

Nevertheless, we're making -- taking initiatives there. We're trying to get more customers on CPP rates, for example. And we'd like to restart enrollment in our real-time pricing rate. We actually have a real-time pricing rate, but we've stopped new enrollments in that rate. And we're looking at reopening that rate.

And by the way, I didn't introduce myself or my colleague at the beginning, which I should have done. I am the Director of our Demand Response Programs, which involves the development, design, implementation and operation of our demand response programs.

And my colleague is Russell Garwacki, and he is in our regulatory policy and analysis group. And he manages our load research, rate analysis and rate design groups at Southern California Edison.

Thank you very much.

PRESIDING MEMBER PFANNENSTIEL: Thank you. Just one quick question on the rate design issues of the AB-1X issue. I know everybody's looking for some work-around, and given that AB-1X is the elephant in the room, what can we do about it, is Edison considering legislative solution?

MR. GARWACKI: Russ Garwacki, SCE. We have looked at that being really our belief that any solution to AB-1X is going to require going through to the Legislature.

Frankly, we believe that in order to be successful at the Legislature it's going to take more than SCE to accomplish that objective. It would take the other utilities, Energy Commission, PUC, et cetera, to be able to probably successfully pull something like that off.

PRESIDING MEMBER PFANNENSTIEL: And so

is anybody leading the charge on that that you know of?

MR. GARWACKI: At this time, absent a significant critical mass we're not going there yet.

PRESIDING MEMBER PFANNENSTIEL: Okay.

COMMISSIONER ROSENFELD: Could I make a remark. This issue was bound to come up today, so I did talk to President Peevey over the weekend. I knew this issue was going to come up today so I did talk to President Peevey over the weekend, who told me that there was a meeting in February with the CEOs of the three utilities including yours, of course. I'm not telling you anything you don't know.

And it was agreed that it was time to go to the Legislature and according to Peevey, this gentle task was given to Peevey and to John Bryson. And they do have -- they are arranging some sort of a date to discuss this sensitive issue with Mr. Nunez. But it hasn't happened yet.

PRESIDING MEMBER PFANNENSTIEL: Right.

COMMISSIONER ROSENFELD: And it is a tricky issue.

PRESIDING MEMBER PFANNENSTIEL: Other

questions? Okay, thank you very much.

MR. HUNGERFORD: All right. I'd like to complete the panel this afternoon and ask those invited to participate --

COMMISSIONER ROSENFELD: David, a little louder.

MR. HUNGERFORD: -- those invited to participate to please come to the table. Mike Alexander from PG&E, I believe, is listed; and Leslie Willoughby from San Diego Gas and Electric; Scott Tomashefsky from NCPA; and I believe Vicki Wood from SMUD is going to participate, as well. And I think there are enough chairs for everyone.

And I believe Scott has some remarks that he has already prepared; is that correct? Do you want me to not put you on the spot? If anyone else has anything that they've already prepared, we could start there. And if not, we can simply open the discussion.

MR. TOMASHEFSKY: Do you want to create flow so you have the investor-owneds take care of their issues, and then we can kind of fire off our issues, and go that way? Your call.

MR. HUNGERFORD: Actually that would be the Chairman's call.

PRESIDING MEMBER PFANNENSTIEL: Scott, go ahead.

MR. TOMASHEFSKY: Thank you. Good afternoon. It's always a pleasure to be back here.

Today I'm going to speak to some of the issues representing NCPA; certainly not speaking on behalf of SMUD, which Vicki will do; or DWP or SCAPPA, for that instance, although I imagine that some of the comments that I make would probably be applicable to a lot of the smaller utilities. And that's been kind of our manta through a lot of what we've been doing here over the past two years.

I think when you look at demand response and you look at the POU's role in that, it comes down to a matter of stepping back and saying, what's the fundamental objective of a lot of the state policy initiatives that we're addressing. And really what it comes down to is reducing fossil-fired generation. That's paramount how that works.

That being said, the combination of the loading order, which looks at energy efficiency and demand response and renewable resources and those things, and other pieces of legislation, has kind of given the municipal community a little bit of flexibility as to how they make those things happen. Which is important when you start to step back and look at demand response measures.

A lot of what you've heard today has been really focused on demand response programs with the investor-owned communities. Looking at some of the numbers that they've put out, look at the targets that they've had to address, it's been somewhat easier to shape programs in a much more statewide perspective, looking at much larger utilities.

When you start to peel away from that and you look at what our role in all of that is, it's almost like taking a PG&E service territory and separating it into 30 different counties, 35 different counties, from what they represent.

And so a demand response program, from a utility perspective, looking at 4 million customers, may not be as effective on the coast as it will be in the Central Valley, as it might be in the Sierras. And that becomes kind of our perspective on how a lot of our utilities have to look at these things.

And so when you look at demand response programs, you look at things like what's the load factor associated with various utilities. You look at some of our coastal utilities. You won't find much peak load there in the summer. In fact, you'll find some of those in the winter.

And so when you start to look at those particular issues, demand response programs certainly may not have value that they will have in other areas.

When you start to go to the Central Valley there's the potential of having those be much more valuable.

The other side of that equation is you have to look at the objectives for demand response. You're looking at the issue of system reliability and whether it was done purposely or by virtue of luck, dealing with the energy crisis. POUs have generally been fully integrated and fully resourced.

So the value from the perspective of reliability is a little bit different. And that also fits in with the construct of how we deal with our cost structure. So our rate designs are a little bit different. So I think it's important to kind of keep that in context.

That being said, I don't think you'll find POUs shying away from demand response programs. SB-1037, the first report that we provided to you in December, gave a first snapshot; focused very much so on energy efficiency, but there was also part of the and equation, which was and let's find out about our demand response programs.

What we reported at that time is that 12 of the publicly owned utilities out of 39 had demand response programs. A number of them deal with demand response in a load-shifting way, through time-of-use rates. Certainly nothing dynamic, but from the construct of the fundamental objective of reducing peak load, we are certainly going in that position.

So when we think about demand programs, you look at some of our members. Roseville Electric has been very actively involved in -- well, not only are they growing leaps and bounds, they have been actively interested in the PCT issue. They have full expectations of that as part of Title 24. They're going to be moving forward with those, implementation of the thermostats there.

You'll find that in other areas, as well. I think when you look at whether you're imposing a program through dynamic pricing, dynamic pricing creates a lot of issues for local governing boards; gets them a little bit nervous in terms of what the true impact is on customers. And, again, what the ultimate objective and the value of putting those type of provisions in place, probably some things that need to be talked about.

From the perspective of the public power community and the fact that the discussion has gone very much forward in the area of demand response to the IOUs, I think similar consideration in terms of how we're dealing with energy efficiency here at the Energy Commission, how it applies to POUs, would be an appropriate way of addressing the issue in the public power community.

We wouldn't want to see you taking actions that would have a negative consequence on public power without making sure that that portion of the debate fully influences the ultimate decisions that you end up making.

So, we would suggest that we take the pace of looking at demand response programs in the similar way we're dealing with energy efficiency, which is first, let's tell you what we're doing; second, let's take a look at what our goals are, and how we set goals. And then talk about evaluation. I don't think we're quite there yet in the grand scope of the public power community.

One final note to make on that issue is that much of what we've said in energy efficiency and that equation, the 12 largest utilities represent about 95 percent of efficiency savings and the like there. I think in terms of demand response, potentially you'll probably see something differently.

And so we don't want to hamstring development of standards or anything to that effect by virtue of the fact that there's a lot of small utilities where there may be very little value added that you get out of focusing demand response programs that might negatively impact them at the local level.

With that I'll turn it back to Chairman Pfannenstiel.

PRESIDING MEMBER PFANNENSTIEL: Thanks,

Scott. Any questions? Why don't we then go to PG&E.

MR. ALEXANDER: My name is Mike Alexander; I'm a Manager within the demand response department at PG&E; the newly formed demand response department, as we've consolidated much of the responsibility of demand response formerly among three or four different offices, under a single officer and one director. So it's all in one piece today.

PRESIDING MEMBER PFANNENSTIEL: Which officer is that, what area of the company?

MR. ALEXANDER: This is in the customer side of the house, so it's Helen Burt.

The one thing that struck me this morning in Ahmad's presentation was I couldn't help but think back to an old song by Peter Allen of "Whatever's Old Is New Again", thinking back to the '70s.

And we talked a little bit about the bundling of energy efficiency and demand response back in those days. And over the years how it had been bifurcated or separated.

I would hope that, as we move forward, that we really look at the customer side as really being a continuum or all of the pieces put together. Customer education, looking at energy efficiency, energy conservation and demand response as being a piece of that that completes it, along with customer generation that might be out there.

We're really very supportive of cost effective energy efficiency, but cost effective demand response. And in terms of the OIR which is going on, the cooperation between the regulatory bodies is essential to doing that.

The one area that we'd like to really point out, however, is customer education is extremely important in this. We talked a lot about automation and how automation can help; but there's a very very strong customer element to it, because automation alone simply will not get us where we need to be.

Larry had mentioned earlier that we have many small customers out there, those smaller-than-200-guys. And they're out there busy doing what they do on a daily basis in their jobs. And they really don't have the opportunity to hire energy managers who are very versed in really the technology or doing these types of things on a daily basis. So, we need to make it easy for them. So anything that can be done from a standards process that really brings in education is very very helpful.

Another area is the ISO. We talked about that 5 percent standard that we have out there today. And that 5 percent really represents the sign-ups, the contracted megawatts that we have out there. But on any given day what do we really get when the button gets pushed and we really need that DR. It's quite a bit less than the 5 percent.

What we need as we move forward, we're very supportive again of pricing options; giving those things to customers. But we want to make sure that they actually act on the says that we need the button pushed. And we need the ISO, as we get history, operating history, to be able to have trust that they will get the megawatts that they plan to get or they think they're going to get.

What we don't want to get is into a situation where we're paying customers to do something and the ISO is also going out there and buying megawatts, as well. So we don't want to be paying twice for the same megawatt that we're getting.

Also, again, from a customer perspective, when I talked a little bit about the continuum of energy efficiency, demand response and self-gen, customers, themselves, are really chasing the same megawatt or the same kilowatt. And this bifurcation has had an issue of, for instance, with a customer who might install a solar system.

On a day that's a demand response day, however, their baseline has now come down to a point that they're not going to get the demand for those hours that you thought they were going to get. But they have reduced their overall consumption. So they've flattened their load curve. And that, in the end, is really what it's all about.

We're very supportive of the Commission, as well, in supporting PIER and the great work that they're doing, especially with automation.

We talked earlier about not having a program, or an automation program, per se. But the work that they've done has led to, in fact, automated programs that are very very helpful.

They're really getting that 12, 14, 15 percent load drop simply by sending that signal and getting the customers to act.

We want to get the customer human element in there, as well, aside from the automation. Customers can be very standoffish when it comes to automation in terms of, I don't want Big Brother to really interfere with my operation. And that's not really what it's about, because in bringing the human element in, we want these customers to have a strategy, a DR strategy that they employ and the automation simply helps them with that DR strategy.

Other comments I did want to make. Human element. Essentially that's -- the main point is we are very very supportive of standards that you might move forward with. And that we want to make it cost effective DR for customers who actually get those megawatts on those days that we need it.

Thank you.

COMMISSIONER BOHN: Just maybe you don't want to or can't answer, I'm just curious. As we talk about this there's a kind of an implicit assumption, it seems to me, as a newcomer, that there is a kind of a linear process here that we impose standards or create standards, therefore we have a half a dozen or a dozen implementers who can make it all happen.

Does the direct access argument get in the middle of this from a public or policy point of view? And if so, how is it relevant? Or is it simply irrelevant?

MR. ALEXANDER: Larry, want to take a shot at that?

MR. OLIVA: I'll take a shot at it. We do have direct access customers on our large customer demand response programs today. And I don't really think it would be an issue really.

I mean, as long as -- if there are standards that apply evenly to all retail providers, whether they're the utility of the ESP, you know, I think that's fine.

And as long as they're -- right now we have ways of making sure that the parties, you know, when there is a demand reduction and a reduction in the cost to an ESP, for example, of purchasing energy, we had a way to reconcile that in the accounting.

As long as the accounting is there, you

know, I don't think direct access is an issue.

MR. ALEXANDER: May I, also? It just adds a little complication in terms of an element, but it's not something that really is a show-stopper at all.

Basically what it comes down to is a matter of settlements in process. Other than that, we do have, as well, many direct access customers who participate in our programs.

MR. GARWACKI: Jurisdictionally I believe you'd have some issues in terms of do you have the authority to overset the generation rates that these customers are going to be charging them.

It's true that we have demand response for our DA customers. And they are paid for on a reliability basis from all customers. But once you start getting into the notion of establishing their rates, like reliability portfolio standards or reliability standards, there's going to be some certain degree of oversight that's going to have to occur that has previously not occurred.

PRESIDING MEMBER PFANNENSTIEL: SDG&E.

MS. WILLOUGHBY: Hi. My name's Leslie Willoughby, and I'm the Manager of our load analysis group. I did not prepare a formal statement today, but I do have some comments based on the presentations.

Generally I wanted to say SDG&E is supportive and encouraged with the CEC's intent to basically resurrect the load management standards. Especially, you know, setting the product standards and equipment used in load management, like Title 20 and Title 24.

It was really very encouraging to hear Mr. Hofmann's presentation on the status of the PCTs and the price point that they're currently at. And that is extremely important that we would encourage that this technology be made available to as many people as possible. And we encourage the CEC to push that.

It's a key component, as Ahmad showed, that the demand response is almost doubled with the enabling technology, when coupled with dynamic pricing. And SDG&E, I don't know if you know, but in our GRC phase two we did propose a whole set of dynamic pricing rates for all customers. So, that would be really good.

And also, SDG&E is supportive of the CEC making recommendations to the PUC regarding rate designs. But that it would be so much better to make sure that this was a coordinated effort with the PUC and the CEC. That the energy policy on rate design would be very coordinated and not have any kind of conflicting issues.

And one last comment. With respect to the ISO calling DR events, that we also agree with Edison that it is important that the utility be the one calling those events. And we would take, you know, whenever the ISO would notify us, but we would actually initiate those events. That would be our preference.

That's it.

PRESIDING MEMBER PFANNENSTIEL: Thank you. Questions? SMUD.

MS. WOOD: My name is Vicki Wood, and I work in the energy efficiency and customer advanced technologies group at SMUD. And I have not made any -- I don't come with any prepared comments, although I would like to make a few. We will be filing written comments, however, by the -- I think it's June 15th deadline.

And SMUD is generally supportive, I would say, of the Commission establishing demand response and load management standards. And, in fact, we still have active programs and tariffs that originated from the old standards. We still have our ACLM -- our residential air conditioning cycling program. We actually have a pool pump timer program, there's still some vestige of that. And we have commercial TOU pricing; we do commercial audits. So we're still, you know, working away at the old standards that the Commission has set.

In addition, we're in the process of revising and restructuring our rates in order that they better reflect marginal costs. And we're also reviewing and completely restructuring our demand response and load management programs. And this would include the deployment of PCTs as well as auto DR. We're looking at that very seriously.

So we're, on our own, moving towards and setting goals for demand response in the same way that we recently set some pretty aggressive goals for energy efficiency.

We do have some concerns relating to demand response, and these are mainly general concerns that we would want to make sure that the Commission considered in the setting of standards.

One is that we'd want to make sure that

there was some consideration given to the integration of energy efficiency, demand response and load management, especially in the alignment of incentives. As well as in bundling, the bundling of programs.

We also have our own inter- and intra-class subsidy problems which are not going to go away immediately, and so when we do restructure our rates, this is a consideration, you know, to avoid rate shock we're going to have to implement them sort of over time. And how much time that's going to take is under discussion right now.

We also would like to b able to use dispatchable programs. I notice not much attention has been paid here today, as has been pointed out by, I think, SCE, to the old load management programs. But we think that there's some tremendous additional value to be obtained through operational value from being able to dispatch load management -- or dispatch demand response.

And we'd also, echoing PG&E, want to make sure that there was a large element of customer education taken into account.

So, those are concerns -- just some of

the concerns that we're looking at today in the redevelopment of our programs that we would want to make sure that the Commission also takes into account.

But most of all, you know, echoing some of the things that Scott said, I'm sure that our board of directors is very concerned with retaining the ability for us to be able to set our own goals. And not only that, but how we actually meet those goals, whether it be through pricing, demand response or load management in the traditional sense.

And we would also like to be able to define any programs or tariffs that we develop. We, of course, would like to be able to define those program or tariff characteristics. And be able to offer our customers choices in how they meet the standards that the CEC may set.

So, given that, that's sort of --

PRESIDING MEMBER PFANNENSTIEL: Thank you very much. I have a question, a relatively general question that I would ask each of the utilities to respond to, if you choose.

And it really has to do with sort of the fundamental question that we've been kicking around here for the day on -- and we'll use PCTs as the example, although you know, as Ahmad pointed out, it's really only one possible program.

But if the Energy Commission chose to use our load management standard setting authority to require that every home in California had a PCT phased in over some reasonable period of time, I don't know, ten years, 20 years, something like that.

And the responsibility was on the utility to make sure that was happening. How would the utilities respond to something like that? It would be done under our authority presumably with the agreement from the PUC that under their processes they would find a way to make sure that the utilities' costs were recovered.

Would this be something that the utilities then would be willing to agree without enormous battles? I know it's taken us many years and some of us would say 30 years, to get an agreement on metering, compliant metering, that is useful for demand response. And are we looking at sort of another 30 years before we get the PCT agreements or some such device as that?

Anybody want to touch that one?

MR. OLIVA: Well, I'll try; that's a tough one. And I'm not a lawyer so I'm not going to give any legal opinions here.

But, you know, it seems to me, first of all, a significant difference between a meter, which is a utility-owned device, versus a customer-owned device. So, a customer's thermostat is their property.

Nevertheless, you know, what would be the obstacles for the utility to do it or how could they do it, I'm not really quite sure. I mean I think we could tell, for the most part, I mean there's always exceptions, but we could probably tell whether the Commissioner has -- or whether the customer has, and a Commissioner, as well, has a central air conditioner.

And so, you know, through the load and load patterns and AMI, you can probably tell what a customer's load is. And so whether they have central air, and we would be able to identify that customer as someone that, you know, needed a, or making sure that they had a certified thermostat.

So there would be a way to identify.

You know, how it would be actually implemented, you know, and what authority the utility would be given and all of that would remain to be seen.

You know, it would be difficult, I think. But another point is that if you prohibited the sale of noncompliant thermostats at the retail level, then that might be a way to, you know, get the stock out in there replaced eventually with compliant thermostats.

So it may be a combination of, you know, the enforcement, asking customers to replace their thermostats; and retail providers providing those compliant thermostats only. As well as, you know, utility assistance for customers who weren't able to do it, or whatever. The utilities could help them then provide the thermostat, as well as replace it.

COMMISSIONER BOHN: You could, could you not, as part of re-hooking up, I mean we change houses every couple of years in this town, or in this state. So as in so many other situations, when you have a sale that could be part of the new escrow accounts.

So in seven years theoretically you'd have the whole thing done, or could have.

MR. OLIVA: Commissioner Bohn, that's a very good point. Hadn't thought of that.

MR. ALEXANDER: That's exactly the way I would propose doing it, rather than making the utilities the agent for making sure that something like this gets done, which puts the utilities in a bad position. But, also, makes it very difficult to police anyway.

Doing something along the lines of when a property changes hands to be able to require it as part of the escrow, that's done in many situations. I know in San Francisco, for instance, as part of the code there, certain energy efficiency things which need to get done at the time of transfer. And this would be a perfect opportunity to do that as well.

And just as a matter of clarification, when we say all thermostats in California, are we talking about all thermostats that have air conditioning, or all thermostats, period? Because that would also cause some issues with customers in terms of cost effectiveness. Especially those customers at the coast that are actually heating in the middle of the summer, as opposed to having an air conditioning load.

MS. WILLOUGHBY: Yes, I believe San Diego would also be supportive of that. And I don't think it would take 30 years to figure it out. But all these issues are important, and I think we could work it out.

PRESIDING MEMBER PFANNENSTIEL: Scott.

MR. TOMASHEFSKY: Yeah, I think the notion of building it in the Title 24 makes it much easier to implement. And really, you don't want to have the utility be the policing mechanism for a lot of these things.

I do agree with Mike's comment, though, that the cost effectiveness of having a coastal utility o a Sierra utility actually be subject to those same types of PCTs doesn't necessarily pass the cost effectiveness test. And, again, it goes away from the objective of what' you're trying to accomplish there.

MS. WOOD: We've been looking at this very issue since our current -- we want to somehow retain our dispatchable ACLM program, I think. And we're looking at replacing those, some aging equipment. And so we've been looking at these very issues.

It would make it much easier on SMUD if

we, you know, if those standards were in place and we could --

PRESIDING MEMBER PFANNENSTIEL: Other questions of the utility panel? Art?

COMMISSIONER ROSENFELD: A couple of general comments. First, with respect to the universal thermostat for air conditioned houses, at times, so we're limiting the flock a little bit.

Interestingly enough we at the Energy Commission have been thinking about energy efficiency at time of sale anyway. As you said, Berkeley and San Francisco and Pasadena and so on, already have these residential conservation ordinances.

Commissioner Pfannenstiel and I have been involved in talking about audits for energy efficiency at the time of sale anyway. The utility wouldn't be involved anyway because we wouldn't want to calibrate the ordinance with actual energy bills. And so this seems to be a sort of natural extension of that.

I wanted to make a general comment about the Energy Commission's load management powers and what we've been doing for the last five years. As

Ahmad, I guess, mentioned, or Ron Hofmann mentioned, in my mind it's a fuzz now, we have really been assuming load management responsibilities for a long time.

We started off about 2002 after the crisis with joint identical orders to investigate, OIRs, from the Energy Commission and the PUC to look into demand response. Out of that group, a joint stay of operation, which is five years old now. And working groups one, which as I remember was President Peevey and me and somebody from the Power Authority, the now defunct Power Authority. A working group two, which worried about the large customers -- which worried about AMI. AMI has come a long to the utilities (inaudible) is getting ready.

We have always assumed, and now I'm looking at Scott and Vicki Wood, we've always assumed that the same sort -- that the munis, probably the only utilities would piggyback along with whatever we developed. It was easier to deal with three IOUs than -- munis.

But I think we've been working along that direction consistently anyway. What I am beginning to get out of the last few works, which have been very productive, is that it probably is time for working group one to reassemble and look into updating our vision. The vision is five years old. It's a little tarnished and needs updating. The goals need updating.

We need to redefine both the definition of demand responsive goal -- price responsive goal as opposed to a day of reliability goal.

So I think this is a stimulus to build a new polishing up of revisions and I intend to work with the PUC to start doing that.

The only other remark I can make is for the last five years I've been frustrated with how slowly this has gone. We made some little progress, but it's gone slowly.

On the other hand, compared with the last 30 years, I guess we've done all right.

(Laughter.)

PRESIDING MEMBER PFANNENSTIEL: Thank you. Further questions of this panel? I just want to say thank you very much. You've helped us train some of the issues, and we're really encouraged with the level of support and enthusiasm and energy and innovation that you're showing. And we'll be working with you closely as we go forward with the standards. I'm glad to hear that there's no real pushback on the Energy Commission resurrecting our load management setting ability, and we'll move forward. We'll count on all of your agencies for support and help and more advice. So, thank you, all.

MR. ALEXANDER: Thank you.

MR. OLIVA: Thank you.

PRESIDING MEMBER PFANNENSTIEL: Now I think public comment is in order. And we'll start with Jane Turnbull.

MS. TURNBULL: Chairman, Commissioners, Staff, I'm Jane Turnbull of the League of Women Voters. The League supports a role for all mature, able-bodied consumers of energy in the enactment of a comprehensive statewide demand response system.

Thus we support the development of the next generation of load management standards. We're pleased to learn that the technology -- that no technology barriers remain. And we agree with DRRC that the challenges now are to establish a system that is simple and equitable to all consumers.

We support dynamic tariffs. However,

the recent complaints from would-be participants in the California Solar Initiative regarding new real-time pricing tariffs associated with the installation of these systems accent the importance of public understanding; and adoption of a process that is not perceived as benefitting a few at the expense of the many, or the other way around.

The League believes that the time has come to directly link the price of energy to its costs. Just as is the case with the health care industry, cross-subsidization has resulted in both confusion and inequities.

Control of costs will continue to be difficult so long as consumers do not receive direct cost signals.

Overall our members are really enthusiastic about the changes that will bring about general public -- bring the general public into this process.

And we commend you for your vision and your determination. Thank you.

PRESIDING MEMBER PFANNENSTIEL: Thank you, Jane. And we commend you for your help and input and advice along the way.

Questions? Thank you, Jane.

Are there other comments? Anybody else? Yes, please come forward.

MR. HAIAD: Carlos Haiad, Southern California Edison. I was just talking to Ahmad. His analysis focused on PCT and the residential sector. But PCT is actually much broader in its application. And is quite applicable to the small commercial and industrial, which would increase drastically the opportunities for the PCT.

If you can envision a Taco Bell or a Blockbuster, they will never have a full EMS system. But they have air conditioning and the PCT would be a very nice match on that market segment. And as Larry know, we have a lot of customers that would fit within that market segment.

So, as I mentioned, we may work together and revise some of that work.

PRESIDING MEMBER PFANNENSTIEL: Great idea, thank you. Other comments?

MR. HVIDSTEN: Commissioners and Staff, I'm Joel Hvidsten; I'm with Kinder Morgan Energy Partners. And for those of you who don't know who that is, it's a pipeline company. And we have a large system in California and throughout the U.S., as well.

I'd like to support the comments I heard from both SMUD and from SCE concerning the reliability programs. We've been a part of the reliability program for many many years and it's been a successful program. We'd like to support its continuance.

I know in the notice that you gave for this meeting you supported the program there, although this was not the thrust of the meeting. But we support that program and we think it's a good one. It provides from the information that was in the notice, like 3.5 percent of the demand reduction that took place was from that program.

And we have a couple of concerns about this. One is that's changing from the energy basis to a demand basis going to the BIP, as we speak. And we're concerned that the incentives don't decrease because, like any company, whatever incentives you get from some program, you decrease those and you get pushback to participation in a program like that.

Also along with comments that SCE made regarding the third-party control of equipment, we would also comment on that, as well, that that's not a good thing for companies such as ours, because in running pumps and you have gasoline and diesel fuel in the pumps, you don't want to be shutting pumps down by someone else when something else down the system is not shut down. You might have severe safety issues resulting from that.

So we have always maintained control, even though we're part of the I6 and nonfirm programs, we shut down when we're told to. But we control the shutdowns, ourselves. So that's a concern for us.

Also, in terms of the reliability, we'd like to have the systems of notification changed because they're different between the PG&E and SCE systems that we're part of, the amount of penalties that we pay -- we would pay if we were in violation -- are different significantly between the systems, as well.

We'd like to have it more uniform. For instance, with the VIP program we're using a battery-powered pager to notify us. Now that means someone's got to change the batteries every month to make sure that they're effective, that nothing happens with this.

We just feel that there could be a better way of notifying us, and would like to request that change.

Thanks.

PRESIDING MEMBER PFANNENSTIEL: Thank you, sir.

COMMISSIONER BOHN: Smoke signals.

PRESIDING MEMBER PFANNENSTIEL: Smoke signals. I believe those are PUC tariff programs, and probably should be raised in that context. Thank you for raising these points here.

Somebody else?

MR. DAY: Good afternoon, Commissioners. My name is Michael Day. I'm here representing ICE Energy. We will be filing more extensive written comments later, but I wanted to pass on a couple of points.

First off, generally speaking, tariff structures that shield customers from the true cost of service realities for the top 40 to 200 hours are what we have now. The closer we move to tariff structures that represent the true cost of service for this top 40 to 200 hours, the better it is for energy storage. And this is responding specifically to some of the questions about energy storage that came up in the morning session.

We look forward to working with Mike's group on what can be done and what should be done with regards to development of tariffs towards energy storage. We would like to illustrate again the difference between permanent load shifting, whether it's ICE storage air conditioning, thermal energy storage, whatever it is technologically neutral. But there is a difference between permanent load shifting and those items which are dispatchable.

Another point is that most of the manufacturers of the energy storage technology who design them to be permanent load shifting have the capacity to be dispatchable. If, say, there's an unusual event that occurs early in the day, that load shifting capacity for many different technologies can be shifted for what's for the good of the general public.

But the problem is that in terms of tariff design, if just because of a forest fire it needed to happen from 10:00 in the morning until 4:00 in the afternoon, and then there was a spike on the customer's bill because the storage had been eliminated, you'd want to make sure that there was some way to insulate customers from those effects, if they were called on an emergency basis.

There's also a movement in storage towards energy neutral or better. So, we're seeing that as sort of a differentiation between different technologies and manufacturers. There's a concentration on storage technologies that round-trip, at the site, as opposed to source, are providing round-trip kilowatt hour neutrality.

Just getting back, this isn't from ICE Energy, but getting back to the PCT question. I was in HVAC contracting, doing a lot of replacement work on residential and light commercial when the setback thermostats became the norm.

And gradually that was a gating event that did not receive a lot of pushback from the community that I was in. I needed to tell my customer, well, we can't just put that old mercury stat back on the wall; we have to provide you with a setback thermostat.

That's a mechanism which happened previously and it worked out pretty well. It may take a little bit longer, but it's one that probably, because people know it and are familiar with it, you may end up with less pushback.

And the last point is this, is the persistence of demand response. When we're looking at all the different measures that are out there in the demand response world, persistence is really key when we're getting into heat storms that extend over multiple days.

And if you look at most of the programs that require some form of sacrifice on the part of customers, whether it's temperature, whether it's lighting, whatever it is, there's good research out there that shows that the first day, the second day, even into the third day, you can have some. But that the persistence perhaps isn't there as much.

And so as we look at different forms of energy storage, I would encourage us to look at perhaps a weighted benefit to those forms of demand response which are both transparent to the customer, and perhaps don't impose sacrifices to the extent that other methods of demand response do. Not because it's to be nice to them, but because it does have a real-life impact in terms of persistence of measure.

Thank you.

PRESIDING MEMBER PFANNENSTIEL: Thank you. Any other public comment? Concluding comment from the dais? Anybody on the phone? No, nobody on the phone.

Concluding comments from the dais? No? No.

I personally want to thank David Hungerford and Ahmad Faruqui for setting up and then helping us through a really valuable day. I think, Ahmad, your reports, both of them, were excellent to give us not just the background, but some ideas going forward. And I think that's been really useful to us on the IEPR Committee as we try to think about what our options are on demand response; and specifically the load management standards.

And I want to thank everybody who's here, who participated actively today. A very good day. And I think very valuable for us and the process.

With that, nothing else, we'll be adjourned.

(Whereupon, at 3:23 p.m., the Committee workshop was adjourned.)

CERTIFICATE OF REPORTER

I, PETER PETTY, an Electronic Reporter, do hereby certify that I am a disinterested person herein; that I recorded the foregoing California Energy Commission Committee Workshop; that it was thereafter transcribed into typewriting.

I further certify that I am not of counsel or attorney for any of the parties to said workshop, nor in any way interested in outcome of said workshop.

IN WITNESS WHEREOF, I have hereunto set my hand this 25th day of June, 2007.